Capacity Market Expert Group discussion papers

Section 1 - Introduction

1. This paper presents policy proposals for the Expert Group's consideration in the outstanding areas of the Capacity Market's penalty regime, specifically with reference to the issues of:

    - The operation of the Capacity Market Warning and delivery incentives following the publication of a warning
    - Delivery exceptions/force majeure
    - Penalty regime for refurbishing plant
    - Penalty regime, including termination fees, for new plant
    - Capping of penalty liabilities and the level of the penalty rate
    - Interaction of secondary trading with the penalty regime

Section 2 - Recommendations

The Expert Group are invited to:

- **Agree** that performance in periods of system stress less than four hours after a Capacity Market Warning (CMW) will be relative to a provider's stated intentions as shown via their (F)PNs and the 'x of y' methodology for DSR capacity

- **Agree** to the proposed scope and methodology for the Capacity Market Warning

- **Agree** to extending the current delivery exception provisions to include situations where the electricity market is suspended under Section G of the Balancing and Settlement Code or where the commissioning of new plant is delayed due to National Grid's timescales providing connections to the transmission network.

- **Agree** that refurbishing plant would be required to demonstrate the status of their refurbishment at 12 **and** 24 months after the auction. Plant failing either of these milestones would have their term length reduced to one year, would have their de-rating figures reconsidered and would be ineligible to access multi-year contracts in future.

- **Agree** that new plant failing to meet its Substantive Financial Commitment (contractual expenditure of at least =>50% of scheduled costs) 12 months after the auction will have their agreements terminated and a termination fee of 0.5 x net CONE x capacity obligation applied

- **Agree** that new plant failing to have at least 50% of its capacity operational (ION status) – by the Long Stop Date (18 months after start of first delivery year) – will have their capacity agreements terminated and a termination fee of (0.5 x net CONE x capacity obligation) + measure of damage caused by their non-operational status, applied.

- **Agree** that new plant would have to lodge 100% of their potential Substantive Financial Commitment termination fee as collateral prior to participation in the capacity auction.

- **Agree** that a CMU's[1] penalty cap (Annual Portfolio Cap, i.e. the 'hard cap') will be linked to their own annual capacity payments

- **Agree** that for consultation purposes, each CMU's Annual Portfolio Cap (APC) will be set between 101% and 150% of their annual capacity payments

- **Agree** that for consultation purposes, the level of the 'z' scaling factor will be set to provide for a Capacity Market penalty rate of between £1,000/MWh and £3,000/MWh

- **Agree** that there is no transfer of historic penalty liability with a physical trade of an obligation. Any outstanding liabilities remain with the provider which incurred the original penalties, and have to be settled by that provider according to CM rules

- **Agree** that providers acquiring obligations through the trading of assets subject to capacity obligations, will have their new obligations separately ringfenced from their original obligations

- **Agree** that any new plant wishing to physically trade its capacity obligations for the second delivery year onwards must be 100% operational (ION-certified) at least two weeks in advance of the year ahead auction for that particular delivery year

- **Agree** that the position to apply a 1% reduction in capacity payments per month for new plant not ION certified is removed in light of the previous proposal

Section 3 – Proposal for the treatment of Capacity Market Warnings and delivery incentives

2. The design of the CM penalty regime is based around the concept of a Capacity Market Warning, with no penalty liabilities for stress events not preceded by such a warning or for warnings not resulting in a stress event. A distinction has been made for system stress events occurring within four hours of this warning and events occurring over four hours.

3. For the former category of events (zero to four hours), providers' performance will be relative to their delivery intentions, as referenced through either their (final) physical notifications that had been submitted at the time of the warning, or their 'x of y' baseline if a DSR provider. Providers' (F)PNs will be adjusted to account for Bid-Offer Acceptances issued by the SO or the provision of balancing services that curtail the output of the

[1] Capacity Market Unit

CMU. Providers will be penalised for their performance in stress events if they deviate below their intended position, whilst providers able to ramp up quickly will be paid for their overdelivery at the reverse of the penalty rate.

4. This position was included to reinstate rewards for fast performance, given such incentives were dulled through the introduction of a four hour Capacity Market Warning, and to penalise those plant which trip off, exacerbating the problem. Providers delivering as per their stated intentions will therefore not be penalised, nor receive overdelivery payments, whilst those that ramp up will be paid for their overdelivery, and the faster they ramp, the greater the reward.

5. For the latter categories (four hours plus), providers' performance will be relative to their adjusted load following obligation. Providers delivering below their obligation will be penalised at the same VoLL minus cash out formulation as the zero to four hours category, whilst payments at the reverse of the penalty rate will be made to those overdelivering.

6. Providers' performance in both categories will contribute towards their CM penalty cap – discussed in section 8 of this paper.

7. In both categories providers will be expected to comply with the Grid Code and all other relevant requirements at all times.

Question 1 - Does the Expert Group agree with the proposal for the treatment of incentives based around a Capacity Market Warning?

Section 4 – Proposal for the treatment and methodology for publishing Capacity Market Warnings

Background:

8. The policy design of the capacity market includes a Capacity Market Warning (CMW) which will be published by the System Operator where scarcity is forecast. This warning is to act as a signal to capacity providers to deliver against their contracted obligation; if they do so they will avoid any penalties due to non-delivery while consumers benefit from the stress event being avoided or the depth of the stress event being minimised.

9. The warning needs to be issued wherever there is a credible risk to supply, to ensure that consumers are protected and the reliability standard paid for is delivered to them. However, excess use of the warning introduces costs to capacity providers which will ultimately be borne by consumers.

10. Expert Group members have previously commented that a warning similar in style to the existing Notification of Insufficient Margin (NISM) could provide the necessary signal to drive the appropriate response from participants.

11. This section describes the factors to be considered when preparing a system warning for the capacity market, discusses the existing NISM and the difference between this and the new Capacity Market Warning and suggests a potential trigger point for the Capacity Market Warning.

Factors to be considered for the capacity market warning:

12. The capacity market auction is looking to bring forward sufficient capacity so that demand can be met, in line with the reliability standard set by DECC. To ensure this standard can be met a volume of reserve will be included in the calculation of capacity adequacy, that reserve required to ensure sufficient headroom is available to provide frequency response[2].

13. The Capacity Market Warning should therefore consider:
    - Forecast demand for electricity
    - Requirement for reserve to provide frequency response
    - Available capacity

Forecast Demand:

14. There are two data streams available for forecast demand; National Demand (ND) and Transmission System Demand (TSD). National Demand is defined in the Grid Code as GB National Demand and comprises the total demand in England, Wales and Scotland including transmission losses but excluding demand for station transformers, pumped storage and interconnectors. Transmission System Demand (TSD) is also defined in the Grid Code and comprises the total demand in England, Wales and Scotland including transmission losses and also demand for station transformers, pumped storage and interconnectors.

Reserve Requirements:

15. The requirement for reserve for response has been set out in The Statement of the Energy Balancing Cost Target Modelling Methodology[3]. This describes the requirement for frequency response in terms of largest single loss connected to the transmission system and the forecast demand. This response requirement is then translated into a requirement for reserve, using a factor of 55% for the amount of response available for 1MW of pull back.

Available Capacity:

16. The available capacity figure will build on the “2 to 14 days Output Useable by Fuel Type” published on the BM Reports website. This forms part of the output useable forecast provided by the System Operation as required by the Grid Code (Operation Code 2, 4.1.1). The figure published is the half hourly average MW for the peak half hour

[2] This requirement has been discussed at Expert Group and Expert Group meetings when discussing volume of capacity to contract and interaction between capacity and Balancing Services

[3] Para 5.6 http://www.nationalgrid.com/NR/rdonlyres/99C89E3D-19BF-4460-9C64-8F83AD667BC2/61055/201315EnergyModellingMethodology_DraftJune2013.pdf

in the day. This figure will be updated to reflect MEL data submitted to the Balancing Mechanism and equivalent data from non BM capacity market participants to inform a warning to be published four hours ahead of real time when delivery against Capacity Market obligations is expected.

17. Submitted MEL data is published on the BM Reports website so market participants have visibility of market information approaching real time; equivalent information from non-BM capacity market participants could be published as well.

Trigger Level for a Capacity Market Warning:

18. The existing NISM is triggered if there is insufficient system margin; this assesses the available system margin against the requirement for reserve at 4 hours ahead of real time.

19. A trigger level should be set for the CMW. Available capacity minus Transmission System Demand and reserve for response requirements would be compared to this trigger level and the surplus or shortfall published to capacity market participants. This should provide industry with confidence that the CMW is only issued as expected.

20. The trigger level could be set by translating the likelihood of demand not being met into a volume of capacity. The statistical analysis used to translate the selected likelihood to a volume of capacity would be set out to ensure market participants have visibility of the calculation. This analysis should be reviewed periodically to ensure it is still fit for purpose and that the needs of consumers and capacity providers are still met.

Comparison to the NISM

21. National Grid publishes a number of standard warnings to all market participants to enable them respond to periods of system stress or potential system stress. These warnings inform that there is a risk to system security; the specific warning issued also informs parties about the risk of involuntary demand reduction. While warnings are likely to be issued in order of severity, there is no requirement to publish them in the order as system stress can occur in very short timescales.

22. The NISM is one of this existing suite of system warnings, set out in OC7 of the Grid Code.[4]

23. A NISM will be published when there is insufficient System Margin. When a NISM is issued to users, it will contain the following information:
    - The period for which the warning is applicable
    - The availability shortfall in MW
    - The intended consequences for uses, which would include that the Maximum Generation Service may be instructed.

[4] http://www.nationalgrid.com/NR/rdonlyres/04AEB77E-7085-4767-9857-D98CDA244E7B/6755/03SystemWarning5Apr06.ppt

24. The NISM requests market participants to review their availability. There is no explicit penalty for participants who do not respond to a NISM. High level the expectations of response from market participants are below:
    - Not to make the situation worst (do not start outages
    - Make the situation better (make more plant available)
    - Take preparatory action if required (applicable to DNO)
    - Review imbalance positions and trade accordingly

25. The SO will monitor the available reserve to meet requirements and will publish a NISM in the event that this trigger level is reached. However, the SO has the flexibility to issue an NISM at other times if required to ensure the continued secure operation of the transmission system.

26. The key differences between the existing NISM and the CMW are the flexibility available to the SO when determining the need for a NISM compared to the methodology set out for the CMW and the focus of the warning; insufficient margin against meeting demand.

Expected use of the CMW:

27. The CMW is expected to be issued where the likelihood of failing to demand is greater than a predetermined level. How often this level is reached will depend on the reliability standard set by DECC; a lower reliability standard will result in the CMW being issued more often.

28. For comparison, when margins were last at 4% (2006/7) eight system warnings were issued without any reduction in demand.

Question 2 - Does the Expert Group agree with the proposed methodology and trigger mechanism for the publication of a Capacity Market Warning?

Section 5 - Proposal for the treatment of delivery exceptions/force majeure

29. In principal there are some circumstances where events outside the control of Capacity Providers ought to give rise to force majeure relief as to do otherwise would be unnecessarily costly for end consumers. Therefore under the current design of the CM it is proposed to allow only limited exceptions to the requirement for providers to deliver as per their load following obligation, or (F)PN baseline, at times of system stress or face penalties. A system of post-event tagging will be developed, along the lines of the existing P217 tagging process, to identify those providers which were held off the system by the SO due to transmission constraint issues. Such providers will be considered to have delivered their load following obligation. Providers not subject to the SO's constraining instructions would be required to deliver as per their capacity obligation.

30. It is proposed, however, that the treatment of exceptions in the CM should be further aligned with those for the Balancing and Settlement Code. Under section G of the

Balancing and Settlement Code (BSC) the electricity market is suspended following a Partial or Total Shutdown of the Transmission system[5]. These shutdowns are defined whereby National Grid issues Black Start Instructions to one or more power plants that are capable of operating without an external electricity supply, requiring them to reenergise their local network and eventually power up other neighbouring plants.

31. The suspension of the electricity market involves suspending the normal operation of the Balancing Mechanism (BM) and all contractual and credit positions, the application of a Single Imbalance Price and NGET centrally dispatching all generators. In such circumstances, Lead Parties that are the subject of a Black Start Instruction will receive compensation as specified in the BSC.

32. In addition, section G enables the electricity market to be suspended in response to Secretary of State directions under section 34 of the Electricity Act 1989, or action being taken by HMG, in accordance with the provisions for emergencies and fuel security periods.

33. It is therefore proposed to expand the CM's definition of exceptions to include the suspension of the electricity market under section G of the BSC.

34. In addition, provision will be made for when a new plant is unable to complete commissioning due to National Grid's delay in providing a connection to the transmission network. In such circumstances the start date of the capacity agreement would be pushed back by the length of the delay.

35. It is proposed **not** to extend the circumstances for delivery exceptions beyond those proposed earlier (extension to include section G provisions and connection delays). This will avoid perverse incentives and strengthen the case for providers to build backup facilities (gas or distillate storage), maintain a fuel diverse portfolio or to trade on secondary markets. It will also avoid discriminating between different fuel types at times of system stress – unless exceptions for all fuel types were to be allowed in the CM's design.

36. This proposal will also align the CM and cash out provisions, avoid unnecessary design complexity and a potential slippery slope of exceptions, and avoid creating delivery uncertainty at times of system stress. This alignment between CM and cash out provisions is crucial given the aligned penalty regimes. Further work is ongoing between DECC and Ofgem on the treatment of gas emergencies, especially in context of the latter's Gas Significant Code Review.

Question 3 - Does the Expert Group agree with the proposal to extend the delivery exceptions to include circumstances where the electricity market is suspended under Section G of the BSC or where connection to the transmission network is delayed?

[5] Although this will change by April 2014 as a result of BSC modification P276

Section 6 - Proposal for the treatment of refurbishing plant

37. At the pre-qualification stage, existing plant may elect to be considered for a longer-term capacity agreement, and associated price maker status, on the grounds of undertaking material refurbishment. This section proposes a penalty regime for plant that had been accorded such status and that had been successful in the auction but which failed to deliver to schedule.

38. It is proposed that refurbishing plants are subject to a Substantive Financial Commitment milestone check 12 months after the auction in which they were successful. Plant will be required to demonstrate to the System Operator that they incurred independently verified costs of at least 50% of the refurbishment costs scheduled for that time as detailed in the plant's Refurbishment Plan and Certificate - submitted at the pre-qualification stage as justification for a multi-year capacity agreement.

39. Plant failing to demonstrate such expenditure at this point will have their contract agreement term reduced to one year (i.e. 'T' year), and the System Operator will have the ability to replace the capacity for the T+1 delivery year via the next T-4 auction.

40. Plant will also be required to demonstrate to the System Operator that the proposed refurbishment work detailed in their Refurbishment Plan and Certificate had been completed by the start of the T-2 year (i.e. 24 months after the auction in which they were successful). This demonstration would need to have been independently verified.

41. Plant failing to demonstrate the completion of their refurbishment work by this milestone will have their contract agreement term reduced to one year, and the System Operator will have the ability to replace the capacity for the T+1 delivery year via the T-1 auction.

42. In addition plant failing either of the aforementioned two milestones will have their de-rating figure for the delivery year adjusted, if applicable. In addition such plant will only be able to access the option of one year term lengths for the duration of the Capacity Market's operation.

43. As with the wider aspects of the CM, providers may also be subject to regulatory investigation if gaming behaviour is suspected.

44. Alternative options considered include checking whether the refurbishment had been completed in the pre-qualification stage for the four year-ahead auction in the T-3 year (option 2), or at the end of the first delivery year (option 3). The three options are detailed in the table below:

Option	When is refurbishment checked?	What happens if refurbishment hasn't happened	Implications
1	• Substantive Financial Commitment (SFC) check start of T-3 year • Refurbishment completion check start of T-2 year	• Reduced to one year contract • If applicable, re-de-rate for delivery year • Restrict plant to one year contracts in future	• PM/PT gaming risk • If plant fails SFC (T-3), then can use four year ahead auction to replace capacity for T+1 delivery year • If plant fails completion check (T-2) then use year ahead auction to replace capacity in T+1 delivery year
2	Pre-qualification stage for the four year ahead auction in T-3 year	• Reduced to one year contract • Potential investigation in to whether refurbishment status was genuine	• PM/PT gaming risk • Can use four year ahead auction to replace plant in delivery years T+1 and T+2 • Refurbishing plant will have under a year to complete refurbishment
3	End of first delivery year (T)	• Reduced to one year contract • If applicable, re-derate to a lower level, and reduce payment accordingly • Potential investigation in to whether refurbishment status was genuine	• PM/PT gaming risk • Will be short of capacity for delivery years T+1 and T+2 (as SO would have assumed the plant was contracted for three years)

45. Option one is recommended on account of offering the most appropriate balance between providing an adequate timeframe for plant to complete their refurbishment (two years), the level and type of penalties and ensuring access to replacement capacity.

Question 4 - Does the Expert Group agree with the recommendation for assessing and penalising refurbishing plant that fails to complete its refurbishment to schedule?

Section 7 - Proposal for the treatment of new plant which fails to commission to schedule; determining the termination fee value

Executive summary

46. There are two cases where a new plant will see its capacity obligation terminated and be liable to pay a termination fee.

    - **Case 1**: where a new CMU fails to provide evidence of its substantive Financial Commitment within the year of being awarded a capacity agreement.

    - **Case 2:** where a new CMU fails to deliver on time and is delayed by more than 18 months from the start of the delivery year and has not achieved at least 50% of operational capacity (ION-certified) by this long stop date.

47. It is proposed to set the level of the termination fee ("**TF**") to reflect an estimation of the economic damage from failing to honour a capacity agreement. This will depend on the particular circumstances applying when the capacity obligation is terminated.

48. For "**Case 1**" it is proposed that the economic damage should reflect the costs to the SO of potentially having to pay a higher price for capacity in year-ahead auctions to solve the capacity shortfall. It is recommended to use 50% of net CONE as an "ex ante" approximation for a potential price increase. Under this proposal, a typical OCGT new entrant would be liable to pay a one off TF of approximately £10,000,000.

49. For "**Case 2**" it is proposed that in addition, the economic damage should reflect a negative impact on the system's reliability standard on consumers and capacity market participants. The impact would be estimated by relying on the analytical methodology to calculate the auction target level of capacity. Under this proposal, a typical OCGT new entrant would be liable to pay a one off TF of approximately £16,000,000.

Issue

50. The capacity obligation termination fee plays an important role in rounding up the CM incentive performance package on new plant to ensure timely delivery and minimize the risk of a costly failure to commission new CM capacity.

51. Whilst the termination fee should be set at a level preventing new plants' inefficient behaviour there is a trade-off between performance incentives (i.e. penalty levels) and investment costs (i.e. risk premia) and the ability to secure finance for new generation, in particular, for independent generator players. In this direction, the termination fee cannot be set in isolation. It should account for overall incentives placed on new plant to achieve a correct balance between benefits and cots of incentives and ensuring that the design does not unduly discriminate against new entrants.

52. The value of the termination fee parameter should also be cost reflective, i.e., should reflect "real" economic damage. Failing to commission a new plant imposes costs on society: (1) the SO will have to procure additional capacity at a risk of paying a higher price; and (2) the cost impact derived from a reduction in the system reliability standard[6] on consumers and capacity market participants. Economic principles suggest that these costs should be priced and allocated to developers. Therefore, setting a cost reflective termination fee has the effect of internalizing the impact of these costs on new plant's financial project economics rather than externalizing their impact to society.

53. In addition, the termination fee should not unduly increase the complexity of the CM design and be proportional to the costs of failing to commission a new plant.

54. At a policy level, a well-designed incentive package on new entrants can mitigate the reputational risks of launching the CM as a "de-facto" availability model[7] and/or strengthen the case for EU state aid clearance.

55. This section presents a set of options to determine the appropriate value of the termination fee parameter to be applied in the CM design.

Options for calculating the termination fee

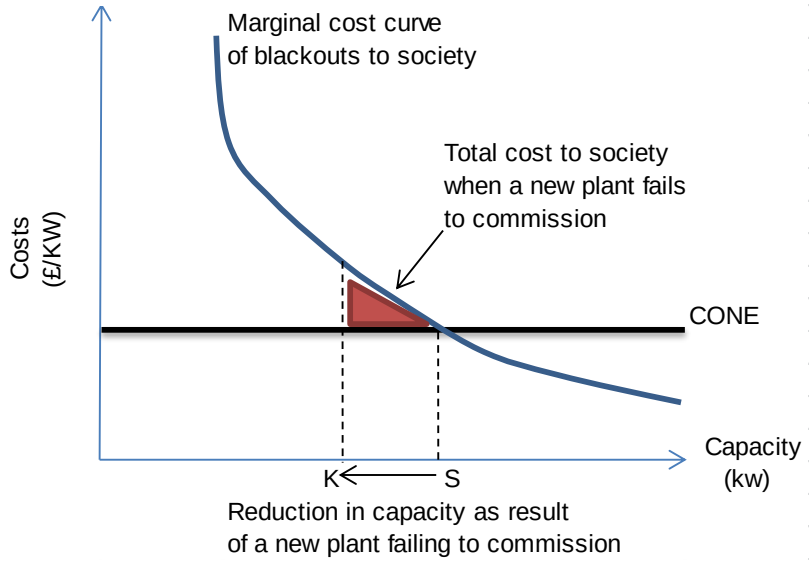
56. The set of options assessed here are explained below:

Option 1 – *The termination fee parameter value is set to reflect the costs to society of a negative impact on the system's reliability standard*

57. Under this option the TF parameter value reflects the increased costs to society of an expected increased probability of costly blackouts during a year (the shaded red area in figure 1 below):

[6] i.e., the expected increase in the number of costly blackouts in any one year.
[7] If Ofgem's minded cash-out parameter values under their SCR were to be implemented in early 2014, the current CM strawman design would become a "de-facto" availability model.

Figure 1: Costs per year to society of a plant failing to commission



Where:

The marginal cost curve of a blackout curve is:

$$Marginal\,cost\,of\,a\,blackout\,(k) = LoLE(k) * VoLL$$

- The marginal cost of a blackout curve is just the loss of load expectation (LoLE) for each level of capacity (k) valued at VoLL, i.e., the expected number of blackout hours for each k valued at VoLL.

- CONE (Gross) is the cost of new entry; S is then the target level of capacity to be procured in a delivery year; and K is S minus the capacity failing to enter the market measured as per the new entrant's capacity obligation.

58. The termination fee becomes **TF1 = Shaded red area**, which is a cost/year estimation. It reflects the estimation of the "economic damage" to society given by: (1) an increase in the expected in the number of blackout hours valued at VoLL; and (2) adjusted to take into account that costs of entry are not incurred (from a society's perspective) at the point of failing to enter the market.

59. Note that this cost, in terms of a reduction in the system reliability standard, remains until the SO addresses the capacity under-procurement problem. Therefore, the TF should account for these factors, and the following formula is proposed to calculate the TF:

60. **TF(x) = x*TF1**, where x is to be determined and it measures the SO's expected time (years) to procure new CM capacity to overcome the security of supply problem.

61. Note that under this formulation the TF would not be a constant fee applied across all types of new plant. It would rather vary according to the new plant's de-rated capacity.

Option 2 – *Set the termination fee at the greater of:*
- *x * [T-4 auction clearing price] * [capacity obligation]; or*
- *x * [Net CONE] * [capacity obligation]*

62. When a new plant fails to commission the SO will have to procure additional capacity to make up for the capacity shortfall. For example, the SO could contract for more DSR in the T-1 auction at the cost of the resulting T-1 auction price.

63. The termination fee should then reflect the economic damage of having to procure additional capacity at a *potentially* higher price to make up for the shortfall. Because the T-1 auction price is not known "ex-ante", the following termination fee formulation is proposed to approximate the potential economic damage:

64. **TF = max [(x*T-4 auction clearing price) , (x*Net CONE)] * [capacity obligation],** where x is either 50% or 25% and is to be determined. Note that the implicit assumption is that the SO will procure either at a price: (1) 50% (or 25%) greater than the T-4 auction clearing price; or (2) 50% (or 25%) greater than net CONE[8]. The TF formulation picks up the greater of both assumed price increases, where x*Net CONE effectively becomes a penalty rate floor.

65. Note that under this formulation the TF would not be a constant fee applied across all types of new plant. It would rather vary according to the new plant's de-rated capacity.

Conclusions

66. Although option 1 might have presentational problems, it provides a simple rule to calculate the TF reflecting the impact on the system reliability standard.

67. The inherent proportionality of the rule makes performance incentives vary in proportion to the impact on system reliability costs: resulting in a lower TF for smaller projects with the converse applying to bigger projects. The proportionality improves the overall financeability of the incentive package under option 1.

68. Further, the TF calculation rule feeds on parameters that are calculated elsewhere to implement the CM. This reduces complexity, increases the coherence and consistency of the overall CM design and gives certainty around the overall penalty level applying to new entrants before the bidding takes place.

69. As a drawback, option 2 does not account for the extra procurement costs incurred by the SO to procure additional capacity which option 2 does account for. This suggests a

[8] Note that net CONE is the "ex ante" estimation of the capacity auction clearing price.

hybrid option 1 and 2, whose formulation would depend on the particular circumstances applying when the capacity obligation is terminated. In particular, the hybrid option formulation should set different TFs depending on the materiality of the impact on system reliability.

70. In terms of option 1, maintaining the high predictability of the penalty design is considered a priority, and therefore the less complex version of the penalty formulation is favoured. This is based on the observation that using either x*net CONE or x*T-4 auction clearing price is always going to be a rough approximation of true price paid to solve the under-procurement problem. Therefore, there is not much difference in using one figure or the other, so it is recommended to minimize complexity and maximizing predictability of the penalty regime. As a result, the following hybrid option is recommended,

$$\mathrm{TF} = \alpha * [x_1 * (\text{net CONE}) * (\text{capacity obligation})] + \beta * [x_2 * (\text{red shaded area in fig. 1})]$$

71. Where the values of α, β, $x_1$and x_2 depend on the particular circumstances applying to the termination of the capacity agreement.

Proposal for implementation of a hybrid option 1 and 2

- ***Case 1:*** *"When a new CMU fails to provide sufficient evidence of their Substantive Financial Commitment to their project within a year of being awarded the capacity agreement".*

72. Two relevant factors determine the particular circumstances under which the capacity obligation is terminated:

    - The new CMU would have its agreement terminated 3 years in advance of the delivery year[9]; and

    - The SO has the certainty, quite in advance of the delivery year, that it will have to procure additional capacity via the T-1 and/or T-4 auctions.

73. Therefore, the impact on system reliability can be neglected in this case. This suggests setting β = 0 in our TF formulation. It is recommended to set $x_1 = 50\%$ which implies a TF of approximately £10,000,000 for our modelled OCGT, based on the following:

74. The design needs to provide performance incentives to avoid inefficient behaviour and induce developers to "sink" a significant part of their construction costs to commit them to provide the agreed capacity.

[9] Note that new CMU will not participate in the T-1 capacity auction.

75. At this stage, the estimated "sunk cost" for a typical OCGT is approximately £14,000,000[10] in terms of technical design, regulatory and capacity market costs. This figure does not seem sufficiently high to commit a new OCGT entrant to enter the market at this stage.

76. The following termination fee formulation is recommended for case 1:

TF = 0.5*[Net CONE]*[capacity obligation]

Question 5 - Does the Expert Group agree with the proposed construct and level of the termination fee for failing the Substantive Financial Commitment milestone?

- ***Case 2****: "A new CMU that has less than 50% of its capacity operational at the long stop date (18 months after the new CMU scheduled commission date)".*

77. Two relevant factors determine the particular circumstances under which the capacity obligation is terminated in this case:

    - The new CMU has less that 50% of ION certified capacity 18 months beyond the delivery year.

    - The SO would have sight of this delay and will be able to monitor the situation, but will have to procure capacity under significant uncertainty.

    - The SO will have to procure additional capacity to address the capacity shortfall via the T-1 and T-4 auctions and plan accordingly.

78. Note that this situation suggests that the impact on the system reliability standard might not be negligible. It is therefore recommended to setting α=β=1 in the TF formulation for case 2.

79. It is also recommended to set $x_1 = 50\%$ and $x_2 = 1$ which implies a TF of approximately £16,000,000. The recommendation is based on the following points:

    - New entrants at this stage face significant opportunity costs of a commissioning delay as they are not receiving revenues neither from the energy market or the CM. Hence, even if they are delayed for 18 months (which would suggest setting$(x_2 = 1.5)$ these additional market performance incentives should be considered.

[10] This figure can be broken down: Our internal data shows that an OCGT's pre-construction costs are £12,000,000. We have added an additional £2,000,000 to account for administrative costs of participating in the capacity market auction. This has been derived from the CM IA.

- Desire to mitigate the risk of allocating capacity payments to speculative projects.
- Avoid the costs imposed on consumers, the SO and other capacity market participants when a plant fails to commission.
- Avoid the occurrence of this type of events in the capacity market.
- The 2012 Electricity Generation Cost Model Report for DECC (page 40) shows that construction times for OCGTs and CCGTs are unlikely to be greater than 3.5 years. Therefore, a new entrant who has been pre-qualified[11] (so, already has planning consent) to participate in the T-4 auction, would be incurring in a significantly inefficient behaviour in this case.
- The TF values are within the range of penalties applying to existing plant. Note that an annual price cap of approximately £50,850,000 would apply to our modelled OCGT (assuming a £2,000 MWh CM penalty rate). A penalty of £16,000,000 would be reached approximately after 14 stress event hours.

80. As a result, recommend the following TF formulation for case 2:

$$\mathbf{TF = [0.5 * (net\ CONE) * (capacity\ obligation)] + [(red\ shaded\ area\ in\ fig.\ 1)]}$$

Question 6 - Does the Expert Group agree with the proposed construct and enhanced level of the termination fee for failing the Long Stop Date milestone?

Section 8 – Implementing the capacity agreement termination fee for new entrants

Executive summary

81. Internal stakeholders have raised concerns around the practicalities of implementing the proposed termination fee (**"TF"**) for capacity agreements allocated to new plant. In particular, it was argued that the termination was unlikely to "bite" where a new plant saw its capacity agreement terminated and had insufficient funds to pay the TF where the capacity provider became insolvent or had financial difficulties.

82. New plant will be required to provide collateral before the T-4 auction takes places. This would represent 100% of the TF payable if the new plant failed to provide evidence of its substantive financial commitment within a year of being awarded a capacity agreement.

[11] Note that for pre-qualification a new entrant would have had to provide: (1) Evidence of a valid TEC agreement; (2) A credit reference; (3) Provide evidence of relevant planning consent; and (4) Submit details of construction milestones to the SO.

83. Where a new plant meets its substantive financial commitment milestone the collateral will be returned to the capacity provider.

84. No collateral would be required for the TF payable where a new plant fails to deliver on time and is delayed by more than 18 months from the start of the delivery year and has not achieved at least 50% of operational capacity (ION-certified).

Background

85. There are two cases where a new plant will see its capacity obligation terminated and will be liable to pay a TF:

- **Case 1**: where a new CMU fails to provide evidence of its substantive financial commitment within a year of being awarded a capacity agreement. Under our proposed methodology, a 565 MW OCGT new plant would be liable to pay approximately a TF of £10,000,000.

- **Case 2**: where a new plant fails to deliver on time and is delayed by more than 18 months from the start of the delivery year and has not achieved at least 50% of operational capacity (ION-certified) by this long stop date. Under our proposed methodology, a 565 MW OCGT new plant would be liable to pay approximately a TF of £16,000,000.

Option assessment

86. In appraising the options we attempted to balance the strength of incentives without raising the burdens to new entrants and to minimize the complexity of the overall penalty regime applying to new entrants:

Case 1 (12 months post auction)

87. In this case, there is a significant risk that new plant sponsors might not have ringed-fenced sufficient funds to pay for the capacity termination fee in the event that the capacity agreement was terminated. Therefore, we recommend that:

- The new CMU is required to provide collateral in the pre-qualification stage. This would be returned for CMUs that are not successful in the relevant auction.

- This collateral should represent 100% of the termination fee liable to pay if the new CMU failed to achieve its substantive financial commitment milestone (12 months post auction) to minimize the burden to new entrants.

- The new CMU will be able to choose the most suitable collateral "tool" from Ofgem's Best practice guidelines for gas and electricity network operator credit cover. These "tools" include:

    - An approved Letter of Credit or equivalent bank guarantee from a bank with a long term debt rating of not less than A by Moody's KMV or Standard & Poor's;
    - Cash deposit/prepayment (payment made before the delivery of the service);
    - Advance payment (payment made after the delivery of a service but before contract settlement);
    - An approved ESCROW account;
    - A performance bond (provided by an insurance company, not a bank);
    - Bi-lateral insurance; and
    - Independent security.

- The new CMU achieves substantive financial commitment milestone will see its collateral reimbursed.

88. In terms of implementation of this proposal, we note that there might be significant challenges as the settlement body will not be set up and running by the time the first T-4 auction takes place. Therefore, there is a question around where the collateral will be hold. We are currently engaging with DECC's Institutions team to address this issue.

Case 2 (18 months post start of their first delivery year)

89. The risk that new plant sponsors have reduced funds to pay for the TF in this case is significantly reduced. Even though the new CMU has failed to bring forward at least 50% of ION-certified capacity it is likely that some capacity would have been built already - note that it has already provided evidence of its substantial financial commitment. Therefore, the likelihood is that the new CMU will have operating capacity in place that will allow it to generate revenue to which to secure that termination fee is payable.

90. We acknowledge that this approach does not ensure with complete certainty that the TF will be paid in this case. However, mitigating this risk completely implies that new CMUs should be required to provide collateral for a long period of time increasing their working capital requirements.

91. As a result, we do not think that the benefits from mitigating the risk of TF enforceability out weight the costs of making new entry more costly and increasing the complexity of the penalty regime. Further, there is a significant likelihood that sufficient ION-certified capacity will be available at this point to secure the enforcement of the TF.

Question 7 - Does the Expert Group agree with the proposal for new plant to lodge collateral, and with the types of approved collateral?

Section 9 - Proposal for the capping of CM penalty liabilities

Issue

92. Internal governance bodies have noted and agreed the proposals to scale the 'z' factor in the CM's penalty regime to accommodate the interactions emerging from Ofgem's significant code review (SCR). Ofgem is currently consulting on their proposals, and if implemented would see cash-out prices spiking to £6,000 MWh in times of system stress.

93. In anticipation of super-high performance incentives in the energy market, it is proposed to refocus the CM's penalty regime on other competing objectives. This is with the view that a £6,000 MWh cash-out is sufficient to ensure that: (1) capacity providers are available and generating in times of system stress; (2) provides robust incentives for DSR to come forward; and (3) that GB is importing through the interconnectors at times of system stress.

94. Crucially, DECC's expert academic consultant was confident that a £6,000 MWh cash-out price provided robust performance incentives, and he advised the redesign of the penalty regime such that: (1) it provides a disincentive to over-state capacity at the outset; and (2) ***to claw back payments from those providers with de-rating factors not matching their performances in stress events***.

95. Issue (1) is addressed via the System's Operator central de-rating of plant. To address issue (2), ***it is proposed to link the annual penalty cap formulation to a provider's capacity payments***.

96. The Policy Forum agreed with this new proposal for the penalty regime and that a penalty equivalent to a "scaled" Value of Loss Load (VoLL) should be applied to capacity providers outside the balancing mechanism. It also agreed to maintain flexibility around the "z" scaling factor in the penalty rate formulation. This should facilitate setting the CM penalty rate appropriately in response to the SCR's final outcome, which is expected in early January 2014.

97. This section, therefore, presents an assessment of different options on: (1) alternatives to link the annual penalty cap to a provider's capacity payments; (2) the level at which the annual cap should be set; and (3) our proposed way forward to determine the appropriate level at which to set the "z" scaling factor.

Option assessment

98. The assessment is structured as a decision tree where each sub-section ends with a recommendation and the following sub-section assess the alternative options in light of that previous recommendation. This is to provide clarity on the interdependencies emerging between different options and a framework to minimize the assessment of alternative option permutations which could complicate the exposition of the analysis.

99. At a high level, the decision tree is organized as follows:
    a) choose the appropriate **structure** for the annual price cap
    b) choose the appropriate **level** at which to set the annual price cap; and
    c) choose the penalty **rate** at which to reach the annual price cap level.

Options for linking the annual penalty cap to a provider's capacity payments

100. The following options have previously been considered for capping overall penalty liabilities:

a) ***Set the annual penalty cap at an absolute level***. For example, as currently proposed in strawman, use net CONE (£35/KWh) to calculate the annual penalty cap. (dropped as per Policy Forum paper – 20130620).

b) **Set the annual penalty cap at a plant's own annual capacity payment**. Note that in this case, the annual penalty cap will differ among capacity providers.

c) **Set the annual penalty cap at *plant's annual payment level, but calculated on the basis of that delivery year's T-4 auction price***. Note that in this case, the annual penalty cap will also differ among capacity providers

d) **Set the annual penalty cap at the lesser of option (b) and (c).**

101. The analysis of options was undertaken where the main objectives for capping penalty liabilities were:

- **Removing risk of existing plant wishing to opt out when the capacity price is low** - by ensuring that plants awarded low-value contracts have a limited penalty liability level.
- **Ensure consistent dispatch incentives between providers** – to maintain incentives to make use of the most cost-efficient plant mix, rather than the plants with the greatest incentives in terms of their CM penalties.
- **Claw back capacity payments from poorly performing providers**

	Risk on existing plant if participates in the CM	**Efficient dispatch incentives**	**Claw back Capacity payments**

Cap set by each plant's capacity payment	Penalty levels proportional to capacity payments	Different plant vintages each have different level of incentives. *However, this risk is severely mitigated with super-high cash-out prices in the energy market.*	Penalty levels proportional to capacity payments
Cap set by that delivery year's T-4 clearing price	Penalty levels might increase in disproportion to capacity payments	All CM plants always have exactly the same incentives	Penalties and capacity payments are not linked.
Lesser of plant's payment and clearing price	Always choose the APC that implies less overall potential annual liability	Incentives equalised if T-4 prices fall over time, but not if they go up	Penalties and capacity payments are only linked when the lesser is the plant's capacity payments

102. Based on the analysis in table 1, it is proposed that setting the APC at a plant's own annual capacity payment strikes provides the best balance between the competing objectives. This option is therefore recommended.

Question 8 – Does the Expert Group agree with the analysis presented in the table above?

Question 9 - Does the Expert Group agree to set the Annual Penalty Cap relative to each CMU's annual capacity payments?

Options to determine the overall hard cap level and penalty rate

103. Following the recommendation above, the annual penalty cap ("**APC**") formulation becomes:

$$APC = \boldsymbol{x} * \sum_{i=1}^{Units\ in\ Portfolio} CMU(i) capacity * capacity\ price_{Tti}$$

- Where x is a percentage value, e.g., 100%. and "$capacity\ price_{Tti}$ " is the clearing price in auction T (T=1 or 4 indicating T-1 or T-4 auction) for delivery in year t for CMU i.

104. There is a need to determine the appropriate value for x. In calibrating the level at which to set the penalty cap and the penalty rate a significant trade-off emerges between:

a) The risk of participating in the capacity market (**"CM"**), and therefore, the extent to which independent players are able to access and secure capital from alternative financial resources at prices that allow entry in the CM ; and

b) The ability of the CM to incorporate a meaningful penalty regime which represents value for money to consumers.

105. Representation from independent generator has suggested that setting an annual penalty cap above 35% of net CONE would prevent them to rise funding either from lenders or equity providers.

106. However, setting a low APC level (e.g., 50% of annual capacity payments) and a low penalty rate (**"PR"**) (e.g., £2,000/MWh) would jeopardize the CM's ability to ensure value for money to consumers as poorly performing providers – including existing and new plant - would see limited reductions in their annual capacity payments. To mitigate this risk a higher penalty rate (e.g., £5,500 MWh) might have to be set to ensure that consumers only pay what they get for.

107. Setting the APC level at 100% of annual capacity payments would, at least, mimic energy-only market outcomes whereby market participants that fail to be available and generating at times of system stress would fail to recover, at most, all their "missing money".

108. In addition, if the APC level were to be set above 100% (e.g., 150%) it would minimize the risk of gaming in the CM, as it prevents providers that never intended to perform in the CM from taking a gamble with the expectation of receiving capacity payments without facing significant penalties.

109. Whilst a cap above 100% would increase the penalty risk and raise barriers to entry, it also allows for setting a lower penalty rate (e.g., between £1,000/MWh - £3,000/MWh) while ensuring value for money to consumers and reducing the penalty risk to new entrants from participating in the CM.

110. Further, there are a series of key features built into the CM's design to help mitigate a provider's exposure to CM penalties, such as:

- Freedom to price their perceived risk exposure into their auction bid.
- Scaling of obligations at times of system stress to account for system demand at that time ('load following').

- Ability to physically trade or financially hedge capacity obligations (although a track record of trading may be required before the debt financing community's concerns are allayed).
- Obligations adjusted for performance in National Grid's Balancing Services.
- Delivery obligations are not binding unless preceded by a Capacity Market Warning.
- No delivery obligations if there is a failure in the transmission system.
- Suspension of obligations if the electricity market is suspended.
- Payments for delivering more than the obligation level.
- An annual price cap linked to an own provider's capacity price.

111. Therefore propose to consult on the following parameter ranges for the APC levels and the penalty rate value:

a) Annual Penalty Cap level (APC): To be set between 101% and 150% of a provider's own annual capacity payments.

b) Penalty Rate (PR) or implied Z factor: To be set between £1,000/MWh - £3,000/MWh topping up an expected cash-out price incentive of £6,000/MWh by the first CM delivery year.

Option assessment

112. Figure 1 below provides a sketch of the options that been considered:

Penalty rate

£5,500/MWh

Option 1 - (Low CAP, High PR) • Design might be more suitable for independent generators that rely on project finance as it can be calibrated to ensure that project debt is recovered in a significant downside scenario. • May lead to excessive entry, but lower CM auction prices. • Ability to mitigate existing plant gaming incentives is jeopardized.	**Option 2 - (High CAP, High PR)** • Excessive CM penalty risk raises a significant barrier to entry in the CM leading to reduced competition in the capacity auction. • Option not considered further given the considerable risk of restricted competition in the CM auction.
Option 3 - (Low CAP, Low PR) • CM penalty design too skewed towards new entrants leading to excessive entry in the CM. • Existing plant, which represents the significant proportion of CM	**Option 4 - (High CAP, Low PR)** **OPTION RECOMMENDED FOR CONSULTATION** • Mitigates the risk of gaming of existing plant.

capacity, will not see its capacity payments reduced in the event of poor performances. • Option not considered further because the CM design is jeopardize in ensuring value for money to consumers.	• Design might be less suitable for independent generators that rely on project finance, but penalty risk can be reduced to new entrants by setting a low PR. • Piggy backs on the effectiveness of other CM design elements that mitigate CM penalty risk.

100% 150%

CAP LEVEL

113. As explained in figure 1, options 2 and 3 are not considered because of they are not likely to result in a balanced outcome in terms of competing CM design objectives.

114. While option 2 is likely to severely restrict competition in the auction, option 3 is likely to induce excessive entry and increase gaming opportunities in the CM. This is particularly true for already existing plant where providers that never intended to perform in the CM might take a gamble with the expectation of receiving capacity payments without facing significant penalties.

115. A structure as set out in option 1 might be preferable to enhance the financial viability of new plant that relies on project finance. The objective of the CM is not, however, to totally de-risk investment in new capacity to maximize the number of potential entrants. Rather, the CM design should only allow for efficient entry to take place, probably at the expense of higher capacity prices but ensuring that the CM provides value for money to consumers. Whilst option 1 would be the preferred option to increase competition in the CM, capacity payments to poorly performing providers would not be significantly reduced and consumers could end paying in excess for the level of reliability provided through the CM.

116. A structure as proposed in Option 4 ensures that capacity payments are significantly reduced from those capacity providers that are not available and generating when they are most needed.

117. In this direction, we propose that the CM design should at least mimic normal market outcomes. In addition, to mitigate the gaming risk of existing market capacity we propose to raise the standard of participation in the CM and set the APC level within the 100%-150% range.

118. We acknowledge that setting the APC at our proposed levels increases the financial barriers to entry to independent generators that rely heavily on project financing. However, high APC levels would allow for a lower penalty rate at which to top-up the cash-out price mitigating the CM penalty risk.

119. In a pure Performance Related Energy Delivered (PRED) model the penalty rate should be set at £11,000/MWh[12]. As suggested by our expert consultant, that penalty rate could be halved and set at £5,500/MWh to mitigate the risk to CM participants. However, topping-up the cash-out price with a high CM-PR provides little benefit in terms of performance incentives as a £6,000/MWh energy market incentive is already sufficiently high. Therefore, the PR can be set at lower levels to reduce the penalty risk to CM participants, while an APC set at a high level (100% plus) would ensure that CM capacity that consistently fails to perform in any one year is not remunerated and potentially penalized. As a result, we propose to consult on a £1000/MWh - £3,000/MWh CM penalty rate range.

120. In addition, we note that option 4 dovetails with the other elements of the CM design that mitigate the penalty risk from participation in the CM (a list is provided in the Issue section) which should mitigate the financial barriers to new entrants reliant on project finance.

Question 10 - Does the Expert Group agree with the proposed level of penalty cap and penalty rate?

Section 10 - Proposal for the interaction of physical trading and the penalty regime

121. The current Capacity Market strawman (v11) is silent on the fate of any penalty liabilities and capped exposure when the capacity obligations subject to the penalties are physically traded. It is therefore proposed that all historic liabilities remain with the provider which incurred the original penalties, and have to be settled by that provider according to CM rules.

122. It is also proposed that obligations subject to physical trading are sterilised at the point of transfer for the purposes of penalty liabilities and contribution to liability caps. A provider would be considered to have no outstanding/residual liabilities for any obligations taken on via physical trading, and would therefore still be able to incur the obligations full cap liability through its own performance from that point forwards. This sterilisation would occur each time an obligation is physically traded.

123. It is proposed that providers acquiring obligations through the trading of assets subject to capacity obligations (i.e. buying plant rather than trading obligations) will have their new obligations and assets ringfenced in a separate portfolio to their original obligations and plant for the duration of the delivery year in which the trade occurs. Such an approach would mitigate the gaming risk associated with a party with an unreliable

[12] The penalty rate should be set at: PR = VoLL = capacity price/LoLE . If we net off Ofgem's proposed level for the cash-out price this results in a PR = £11,000/MWh.

plant, in an otherwise healthy portfolio, selling the plant to a party which has reached its CM liability cap with the aim that the plant cannot incur further penalties if there are further stress events.

124. The liability caps referenced in section 9 will be applied separately to both portfolios - meaning that the performance of the purchased unreliable plant cannot 'contaminate' the performance of the provider's original portfolio.

Question 11 – Does the Expert Group agree that capacity obligations are physically traded with no associated residual penalty liability?

Question 12 – Does the Expert Group agree that any plant acquired through the sale of assets, and any associated capacity obligations, will be added to a separate CM portfolio to the one containing the acquirers original plant and obligations?

Section 11 – Proposal for the interaction between physical trading and the penalty regime applying to new plant

Issue

125. As currently proposed in the CM strawman, the secondary trading rules interact with the penalty regime for new plant in ways that limit the SO's ability to procure capacity efficiently.

126. Specifically, a situation might emerge where a capacity obligation has been secondary traded, only to be subsequently terminated because a new plant has not met its commissioning deadlines as specified in its capacity agreement, i.e., there is a risk that phantom capacity might be secondary traded where new plant fails to commission on time. If secondary trading rules and/or the penalty regime for new plant are left unchanged, the SO will face considerable uncertainty to determine the amount of capacity to be procured in the year-ahead auctions.

127. Potentially, this could be addressed by revisiting the penalty regime on new plant, but this would be at the expense of: (1) increasing the overall complexity of the penalty design; and (2) limiting SO's ability to prevent secondary trading of obligations. This would apply to situations where the SO may had procured additional capacity in the year-ahead auction to replace capacity failing to commission on time. This course of action severely limits the SO's ability to effectively exercise its delivery role, resulting in this option not being considered further.

128. Therefore, it is proposed to revisit the secondary trading rules applying to new plant because it provides a less complex solution while maintaining the SO's ability to prevent secondary trading in situations where it has already procured capacity to make up for a capacity short fall due to new plant failing to commission on time.

Recommendation

129. It is recommended to restrict new plant from secondary trading as follows:

- New plant may physically trade obligations at any point from a year ahead of the start of the first delivery year and throughout that delivery year.

- New plant wishing to physically trade obligations at any point from a year ahead of the start of the second delivery year and throughout that delivery year, will be prevented from doing so if it is not 100% operational - ION-certified - at least 2 weeks before the year ahead auction for that delivery year takes place.

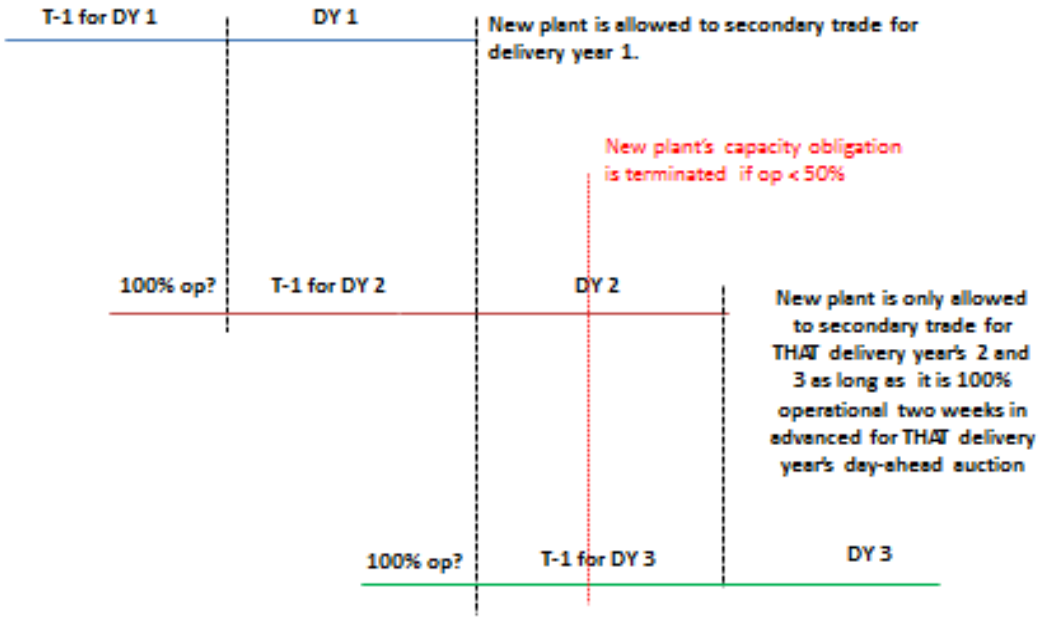
- New plant wishing to physically trade obligations at any point from a year ahead of the start of the third delivery year and throughout that delivery year, will be prevented from doing so if it is not 100% operational - ION-certified - at least 2 weeks before the year ahead auction for that delivery year takes place.

- To avoid over complicating the penalty regime on new entrants and avoid potential double penalties, it is proposed to drop the reduction in capacity payments by 1% per month for every month they are delayed over six months.

Assessment and implementation of recommended option

130. Figure 1 below provides a diagrammatic representation of our proposed changes to the secondary trading rules of physical capacity for new plant, to avoid the situation where a capacity obligation is secondary traded but subsequently terminated because a new plant has not met its commissioning deadlines as specified in its capacity agreement:

Figure 1: Diagrammatic representation of the proposed change to secondary trade rules for new plant



131. Note that under this proposal:

- The SO will have certainty that at the T-1 auctions for delivery year's 2 and 3 the new plant would not have secondary traded capacity obligations. Nevertheless, new plant will have to honour its capacity agreement for the any amount of operational capacity achieved.

- If a new plant has its capacity agreement terminated because it fails to meet the 18 months long stop date by which at least it should have 50% of ION-certified capacity, the SO can be sure that no secondary trading has occurred in relation to this capacity obligation and can procure additional capacity accordingly in the year ahead auctions. So, phantom capacity is prevented from being secondary traded.

- These restrictions on secondary trading can be viewed as an additional penalty on new plant failing to commission on time. Note that while a new entrant who is delayed might be liable for capacity market penalties when a stress event occurs for the amount of its ION-certified operational capacity, it would not be able to physically trade out its position until it has achieved 100% of operational capacity in delivery year 1 or 2.

132. If this proposal were to be implemented it is recommended to adjust the overall penalty package applying to new plant to avoid over complicating the penalty regime on new entrants and potential double penalties. In particular, it is proposed to drop the

reduction in capacity payments by 1% per month for every month they are delayed over six months.

133. Note that restricting secondary trading as proposed, “delayed” new plant has additional incentives to bring forward 100% of operational capacity to be able to hedge physically its position and avoid paying CM penalties in the case that a stress event occurs.

134. In principle, either reducing by 1% per month capacity payments, or restricting secondary trading are a second order effect in comparison with other penalties applying to a new plant to induce a timely delivery, such as: (1) delaying capacity payments until capacity is ION-certified; or (2) the prospect of facing the termination of the capacity obligation. **It is recommended to drop the policy position of reducing capacity payments by 1% per month for every month they are delayed over six months to reduce the complexity of the penalty regime and avoid potential double penalties**.

Question 13 – Does the Expert Group agree with the proposal to restrict the circumstances whereby new plant can physically trade its capacity obligation?

Question 14 – Does the Expert Group agree with the proposal to remove the 1% reduction per month for the capacity payments of delayed new plant?