National Grid Electricity Transmission
RIIO-T1: Initial Proposals consultation response
Supplementary information –
Generation connection uncertainty mechanism

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Executive Summary

1 This supplementary information document summarises the work completed by National Grid on the re-design of a local generation connection uncertainty mechanism, which has been developed in response to Ofgem's simplified approach that was included in Initial Proposals.

2 We recognise that our March 2012 proposal for the generation connection uncertainty mechanism was complex; however, Ofgem's mechanism appeared too simple. We were concerned that Ofgem had reached conclusions regarding the accuracy of their design based on the deterministic consideration of a limited number of scenarios. We have therefore used the comments made by Ofgem to construct a less complicated, alternative option and compared this with Ofgem's mechanism using both deterministic and probabilistic assessments.

3 The probabilistic assessment included in our March 2012 submission was not sufficiently detailed to properly differentiate between zonal and national approaches. In order to address this, we have developed a more sophisticated analysis.

4 The deterministic and probabilistic analyses both demonstrate that the alternative local generation connection uncertainty mechanism developed in this paper is more accurate than the simplified mechanism included in Ofgem's Initial Proposals. The alternative approach represents a lower risk solution for both National Grid and consumers and should therefore be adopted.

Context

5 In our March 2012 submission, we presented some detailed work on the uncertainty associated with local generation connection works. This work included an assessment of both the volume and cost uncertainty, and considered the appropriate risk sharing arrangements.

6 In their initial assessment of our July 2011 business plan submission, Ofgem identified several areas for improvement including ‘increasing the breadth of scenarios and sensitivities eg different demand assumptions’ [Initial assessment of RIIO-T1 business plans; Supplementary Annex; Para 4.60].

7 In response to this point, we broadened the range of scenarios that we used to include:

(a) A high-demand scenario; and

(b) A low-demand scenario.

8 We used these scenarios together with the Slow Progression, Gone Green and Accelerated Growth scenarios to develop probabilistic distributions to describe the local generation connection volume uncertainty.

9 In order to better understand the local generation connection cost uncertainty, we divided generation costs into:

(a) Connecting substation costs – this category covered the minimum generation connection substation cost. This would be required for all new generators and therefore would be applicable on a national basis.

(b) Within-zone reinforcement costs – this category covered other ‘within-zone’ or local enabling works costs, such as equipment to manage short-circuit levels and increase the rating of circuits. These costs were not consistent across zones due to geographical factors that added complexity to the local network reinforcements.

(c) New overhead line and cable costs – this category covered new overhead line and cable circuits required to connect new substations to the main transmission system.

10 Ofgem noted that the ‘within-zone’ costs appeared ‘to be more scheme specific rather than zonal’ [Cost and assessment and uncertainty supporting document; page 39; para 4.77]. This was both accurate and helpful. The split between connecting substation costs and within-zone reinforcement costs was completed by identifying the minimum scheme design elements, categorising them as connecting substation costs and categorising everything else as within-zone reinforcement costs. This led to a number of scheme-specific elements being categorised as ‘within-zone’.

11 In order to model the overall uncertainty associated with local generation connections, we developed probabilistic distributions for the connection substation, ‘within-zone’, overhead line and cable costs. In order to simplify the modelling of the cost uncertainty, we developed a national distribution for ‘within-zone’ works rather than zonal distributions. This simplification limited the extent to which our probabilistic analysis could differentiate between the accuracy of national and zonal risk sharing mechanisms.

12 A Monte Carlo analysis was completed to calculate the uncertainty associated with local generation connections. The volume of new generation and the substation, ‘within-zone’,

overhead line and cable costs were sampled from the probabilistic distributions described above.

13 We then developed and tested a number of volume-driver options with the aim of ensuring that our allowances were adjusted up or down in accordance with the actual level of generation connection. We also sought to demonstrate that any additional complexity was justified by the additional accuracy that it delivered and the consequential impact that this had on the overall risk faced by consumers and ourselves.

14 The volume-driver options that we considered were:

(a) Volume-driver for all local connection costs;

(b) Volume-drivers for substation costs, ‘within-zone’ costs and overhead line and cable costs; and

(c) Volume-drivers for the cost of connections at new substations, connections at existing substations, ‘within-zone’ costs and overhead line and cable costs.

15 We repeated the Monte Carlo analysis with each of these mechanisms and measured the resulting difference between cost and allowance. The most complex mechanism (option (c) above) was the most accurate (the difference between cost and allowance had the lowest standard deviation), but it only offered a marginal improvement on option (b). We therefore proposed option (b) since this appeared to represent the best trade-off between accuracy and complexity.

16 Ofgem stated that they were ‘not convinced from the information NGET provided that disaggregating to this level provides additional accuracy and less risk to NGET and its customers’. They went on to say that they were also ‘concerned about the sensitivity that the zonal drivers had to the background assumptions of demand and closures, which do not seem to be related to the actual within-zone costs incurred in a particular zone’ [Cost assessment and uncertainty Supporting Document; Page 38; Para 4.76].

17 As noted above, Ofgem observed that the ‘’within-zone’ costs appear to be more scheme specific than zonal’. They also stated that information ‘provided by NGET over the assessment period highlighted that in many zones only one scheme out of a group of schemes had ‘within-zone’ costs associated with it’. This led Ofgem to the conclusion that this ‘gives a higher risk that the UCA would either over or under compensate for the level of expenditure incurred depending on whether the scheme had associated ‘within-zone’ costs’.

18 Ofgem proposed a simpler three-volume-driver combination, with a single national volume driver for substation and within-zone costs, and volume-drivers for overhead lines and cables. Ofgem noted that they ‘compared the sensitivity of both NGET’s proposed UCA and [their] proposed simpler three-volume driver combination against some different scenarios. These included, amongst others, the Gone Green, Slow Progression and Accelerated Growth scenarios on which NGET based its March 2012 business plan. For each test the more simple UCA gave a value that was closer to the estimated cost incurred’.

Further uncertainty mechanism development

19 As described above, Ofgem have stated that their proposed simpler three-volume-driver combination gave a value that was closer to the estimated cost incurred for the Slow Progression, Gone Green and Accelerated Growth scenarios. We were unable to repeat this analysis and found that our combination was closer to the estimated cost for each of the scenarios. Ofgem have since confirmed that they agree that our combination is closer for the Slow Progression and Gone Green scenarios.

Categorisation between substation and ‘within-zone’

20 As noted above, Ofgem usefully noted that the ‘within-zone’ costs appeared to be more scheme specific than zonal’. Whilst there are a number of zonal ‘within-zone’ works, there are also some scheme-specific works that, due to the categorisation process, have been identified as ‘within-zone’ works.

21 Ofgem also stated that information ‘provided by NGET over the assessment period highlighted that in many zones only one scheme out of a group of schemes had ‘within-zone’ costs associated with it’. It should be noted that this could be driven by the order in which generation is assessed and connected. For example, if a generator applies for a connection in a particular zone, then NGET will assess the works required to accommodate that generator. If the generator signs the resulting connection agreement and another generator then seeks a connection in the same zone, the new connection will be assessed with the other, newly-contracted generator in the background. This could potentially identify some ‘within-zone’ works which were not required for a single generator but are required for two. Due to the order of connections, these works would only appear against the second generator.

22 This leads to the conclusion that the categorisation of works between the substation costs volume-driver and the ‘within-zone’ works volume driver is problematic.

Treatment of demand changes and closures

23 We understand Ofgem’s concerns with the sensitivity of the ‘within-zone’ works volume-driver to demand changes and closures. Whilst these factors have the potential to impact the cost of the enabling works required to connect new generators, we do not have direct evidence to link ‘within-zone’ costs and these outputs for the majority of zones.

24 There are a number of specific zones where this is not the case however. In the Mid-Wales (Zone RD22) and North East (Zone RD2) zones, the cost is being driven by the connection of embedded generation (effectively negative demand) and by directly-connected new generation. [text deleted] triggers a requirement for additional works at a cost of £46.5m.

25 We share Ofgem’s apparent aim to make the uncertainty mechanism arrangements as simple as possible but, in order to develop an uncertainty mechanism that ignores demand changes and closures, the specific zonal issues mentioned above need to be addressed. [text deleted]. For Mid-Wales and North East, the costs required to accommodate the directly-connected generation and the embedded generation can be included in the calculation of the national or zonal unit cost allowances.

Zonal or national

26 In addition to the changes described above, Ofgem have also moved from our combination of national and zonal volume-drivers to a single national volume driver.

27 We are concerned that Ofgem have drawn conclusions about the relative accuracy of uncertainty mechanism combinations based on the consideration of such a limited number of deterministic scenarios. Probabilistic analysis is also required to assess the accuracy of the generation uncertainty mechanisms due to the scope of uncertainty around the actual generation projects that will commission during the RIIO-T1 period, within and between the high-level deterministic scenarios.

Alternative approach

28 The differences between our March 2012 proposals and Ofgem's Initial Proposals are shown in Table 1 below, together with our comments.

Table 1 – Comparison of uncertainty mechanism features

	NGET March 2012 Proposals	Ofgem Initial Proposals	Comments
Categorisation between substation and 'within-zone'	Some scheme-specific works categorised as 'within-zone'	Single category	Given the issues associated with this categorisation, we agree with Ofgem's 'single category' approach
Treatment of demand changes and closures	Part of the volume-driver for 'within-zone' works, but only have evidence to support this for some zones	Ignored because they 'do not seem to be related'	Provided arrangements are put in place for the zones where there is a demonstrable link, we agree with Ofgem's approach of ignoring demand and closures for the purposes of the main driver
Zonal or national	National substation volume-driver; zonal 'within-zone' works driver	Single national driver	Zonal and national volume-drivers need to be assessed both deterministically and probabilistically to determine the most accurate

29 Based on our comments above, we have developed an alternative mechanism to assess against the approach described in Ofgem's Initial Proposals.

30 This alternative mechanism is summarised below:

(a) Zonal volume-drivers covering both substation and 'within-zone' costs;

(b) Volume-drivers based on the connection of new generation only (demand changes and closures are ignored);

(c) Base funding for [text deleted] and the inclusion of the full Mid-Wales costs (including embedded generation costs) in the Mid-Wales unit cost allowance.

31 The proposed zonal baselines (new generation MW) for transmission-connected generation are shown in Table 2a below.

Table 2a - Baseline zonal MW for transmission-connected generation

Zone	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
2	0	0	299	299	299	299	299	1,699
3	0	0	333	333	333	333	333	333
4	0	1,200	1,420	1,595	1,595	1,595	1,595	3,115
5	0	0	0	0	290	1,190	2,590	3,490
6	0	0	0	750	2,000	2,000	2,011	6,611
7	0	147	432	574	574	574	574	574
8	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0
10	0	0	0	0	0	1,320	1,320	1,320
11	0	0	0	0	0	0	840	840
12	0	0	0	0	0	0	0	0
13	0	0	350	649	649	674	699	724
14	0	0	0	0	0	0	0	0
15	0	250	1,481	1,481	1,481	1,731	1,731	1,731
16	0	0	0	0	0	0	300	3,600
17	0	0	0	500	500	500	500	500
18	0	0	0	0	0	302	2,376	4,450
19	0	0	0	0	0	1,000	1,000	1,000
20	0	0	0	0	0	0	0	0
21	504	504	874	1,860	1,860	1,860	2,860	2,860
22	0	0	176	360	360	360	360	360

32 In addition to the zonal MW identified for transmission-connected generation in the table above, we propose including the mid-Wales embedded generators in the baseline. These are shown in the Table 2b below.

Table 2b – Baseline zonal MW for embedded generation

Zone	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
22	0	0	0	517	517	517	517	517

33 The proposed zonal unit cost allowances (with and without the application of Ofgem's proposed efficiency savings at an assumed 10.8%) are shown in Table 3 below. These UCAs take account of the known costs associated with embedded generation which were previously included in the within-zone element of the uncertainty mechanism.

Table 3 – Zonal Unit Cost Allowances

Zone	Unit cost allowance (£/kW)	
	Without Ofgem's proposed efficiency savings	With Ofgem's proposed efficiency savings
2	22.27	19.86
3	25.93	23.13
4	36.54	32.60
5	18.53	16.53
6	20.62	18.39
7	26.59	23.72
8	None available	None available
9	None available	None available
10	4.89	4.36
11	52.80	47.10
12	None available	None available
13	53.74	47.94
14	15.06	13.43
15	26.38	23.53
16	18.85	16.82
17	64.90	57.90
18	22.68	20.23
19	3.03	2.70
20	7.21	6.43
21	35.69	31.84
22	111.53	99.49

34 For zones 8, 9 and 12, we currently have no new generation connection data. These zones could be handled with a national average or with a re-opener to establish a unit cost allowance when cost data is available.

35 We note that some of the zonal unit cost allowances are very low. Of these, the South Coast (Zone 19) is of particular concern. The current unit cost allowance is based on a limited sample of schemes, and recent connection activity in this area suggests that a much higher unit cost allowance would be justified. We would welcome further engagement with Ofgem on the appropriate unit cost allowance for this zone.

Uncertainty mechanism assessment

36 In order to assess the uncertainty mechanism options, we have completed a deterministic assessment against the three main forecast generation scenarios, Slow Progression, Gone Green and Accelerated Growth. Due to the amount of uncertainty associated with an eight-year control period, we have then gone on to develop an improved probabilistic assessment.

Deterministic assessment

37 Using the unit cost allowances shown above to adjust the baseline allowance against each of the three scenarios provides the allowance outcomes shown in Table 4.

Table 4 – Calculation of UCA-adjusted allowances

Scenario	Adjustment to allowances		Allowance Outcome	
	NG alternative adjustment (£m)	Ofgem adjustment (£m)	NG alternative (£m)	Ofgem (£m)
Gone Green	-153.2	-224.7	748.7	677.2
Slow Progression	-145.4	-213.8	756.5	688.1
Accelerated Growth	77.6	137.0	979.5	1,038.9

38 To identify the more accurate uncertainty mechanism outcomes for each scenario, it is necessary to identify the expected expenditure associated with each of the three scenarios. Within the 'Managing risk and uncertainty' annex of our March 2012 submission, we gave the total expenditure within the RIIO-T1 period associated with each scenario. From this, it is necessary to identify the element of this expenditure that is comparable to the allowance outcome by excluding expenditure associated with overhead lines and RIIO-T2 outputs.

39 The RIIO-T2 outputs can be sub-divided into projects where the full output is delivered in RIIO-T2 (RIIO-T2 outputs) and where part of the output is delivered in RIIO-T1 and the remainder in RIIO-T2 (Partial Work in Progress or WIP). Due to the function of both uncertainty mechanisms, it is necessary to identify these separately. Table 5 shows the adjusted forecast expenditure for each of the three scenarios.

Table 5 – Calculation of costs to compare with UCA-adjusted allowances

Scenario	March 2012 submission (£m)	New build OHL costs (£m)	Costs for RIIO-T2 outputs (£m)	Costs for partial WIP (£m)	Adjusted expenditure (£m)
Gone Green	1,366.7	220.5	-242.7	-149.8	753.8
Slow Progression	1,431.1	220.5	-221.4	-149.0	840.2
Accelerated Growth	1,406.0	220.5	-112.1	-139.3	934.1

40 The values for Gone Green RIIO-T2 outputs are as identified by Ofgem and the partial WIP figure takes account of the proportion of expenditure that delivers an output in the future price control period. The values for Slow Progression and Accelerated Growth are constructed on a similar basis, using the detail of projects to identify expenditure in these two categories.

41 It is now necessary to compare these uncertainty mechanism target values to the allowance outcomes for both the Ofgem mechanism and the National Grid alternative proposal. This is shown in Table 6 below, where the National Grid alternative mechanism is significantly more accurate for each of the three scenarios considered.

Table 6 – Comparison of adjusted allowances with adjusted costs

	Adjusted allowance			Accuracy	
Scenario	**NGET (£m)**	**Ofgem (£m)**	**Adjusted expenditure (£m)**	**NGET (£m)**	**Ofgem (£m)**
Gone Green	748.7	677.2	753.8	**5.0**	76.5
Slow Progression	756.5	688.1	840.2	**83.7**	152.2
Accelerated Growth	979.5	1,038.9	934.1	**-45.4**	-104.8

Revised probabilistic assessment

42 As noted above, in terms of the assessment of the various uncertainty mechanism options, the problem with the Monte Carlo analysis completed as part of our March 2012 submission was the simplified representation of the 'within-zone' works cost. This was modelled as a national distribution rather than a number of zonal distributions, which means that the March 2012 analysis did not properly assess the relative performance of national and zonal schemes.

43 In order to address this issue, we have developed a more detailed assessment approach. The aim of this analysis is to determine the most accurate local generation connection volume driver based on all the information that we have about the potential connections in RIIO-T1.

44 In completing this assessment, we have assumed that:

(a) Specific arrangements will be in place for embedded generation connections in Mid-Wales and the North East and for generation closures [text deleted];

(b) Separate volume-drivers will be introduced for any new overhead lines and cables required to accommodate new generation connections.

45 In each of these cases, we have assumed that the same arrangements will be in place for each of the volume-driver options being considered.

46 We have also assumed that spend in RIIO-T1 to deliver outputs in RIIO-T2 will be the subject of a separate mechanism and therefore this has been ignored from our analysis. This is the subject of another Supplementary Information document (RIIO-T2 Outputs).

47 In terms of the analysis approach, we could simply compare the accuracy of zonal and national unit cost allowances using the coefficient of determination, R^2. The issue with this

approach is that it ignores the relative likelihood of particular generation connection projects.

48 In order to reflect this, we have developed a probabilistic analysis. We have derived a 'probability of connection within RIIO-T1' for all of the generation projects that we are aware of. This includes generation projects that are included in any of our generation forecasts (Slow Progression, Gone Green and Accelerated Growth) and projects with a signed connection agreement (so-called 'contracted' generation).

49 In order to assign probabilities to each of the projects, we developed the matrix shown in Table 7 below.

Table 7 – Project probability matrix

Connection date	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Three scenarios	100%	95%	95%	90%	90%	70%	70%	50%	50%
Two scenarios	100%	90%	90%	80%	80%	50%	50%	30%	30%
One scenario	80%	60%	60%	40%	40%	30%	30%	20%	20%
No scenarios	60%	40%	40%	20%	20%	10%	10%	5%	5%

50 The matrix recognises that generation projects that appear in more scenarios (i.e. they are required against a range of high-level assumptions about how the electricity market will develop) are more likely. It also recognises that projects that are expected to connect earlier in RIIO-T1 are more likely to connect during the RIIO-T1 period than those expected to connect late. Where projects appear in multiple scenarios, the contracted connection date has been used to set the probability.

51 Assigning probabilities in this way is subjective, and therefore we have developed the analysis so that this matrix can be changed to complete sensitivity analysis.

52 A binomial distribution based on the probability from the matrix was used to represent the probability of a generation project commissioning in the RIIO-T1 period. This assumes that the success of every generation project is independent.

53 We then completed a Monte Carlo analysis to determine the forecast costs and outputs for local generation connections. The generation projects were sampled from the binomial distributions described above.

54 The costs and outputs were recorded for each simulation. The cost was then compared with the allowance, where the allowance was calculated as the base funding adjusted by the change in output (MW) multiplied by the relevant unit cost allowance. To ensure consistency, both the scheme costs and the unit cost allowances did not include Ofgem's efficiency saving or challenge.

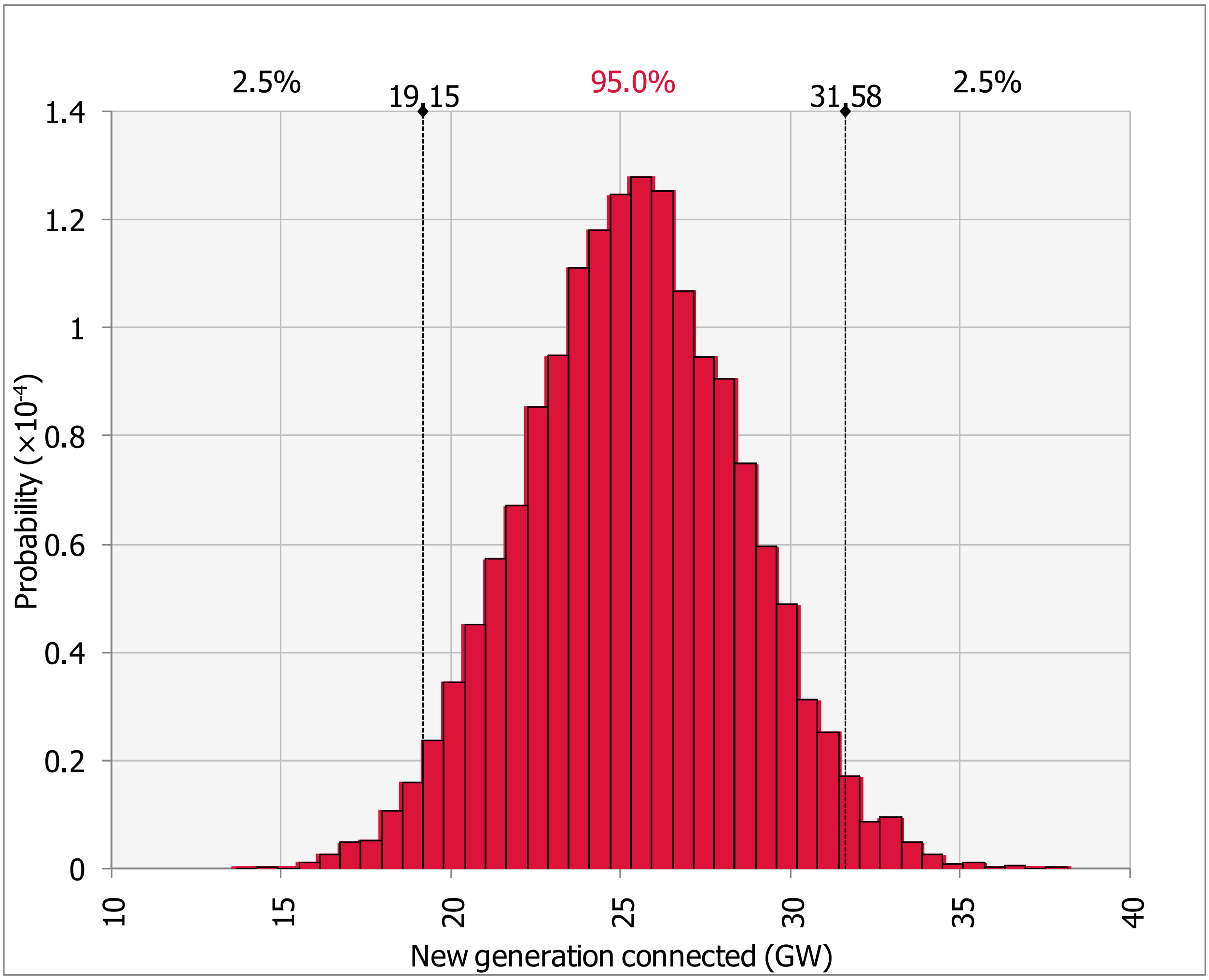
55 Rather than calculate the impact on returns (as with our March 2012 submission), we have concentrated on the capex impact of the competing uncertainty mechanism options.

Results

56 The improved probabilistic assessment described above was used to compare the national volume-driver described in Ofgem's Initial Proposals with the zonal volume-driver described as our alternative approach above.

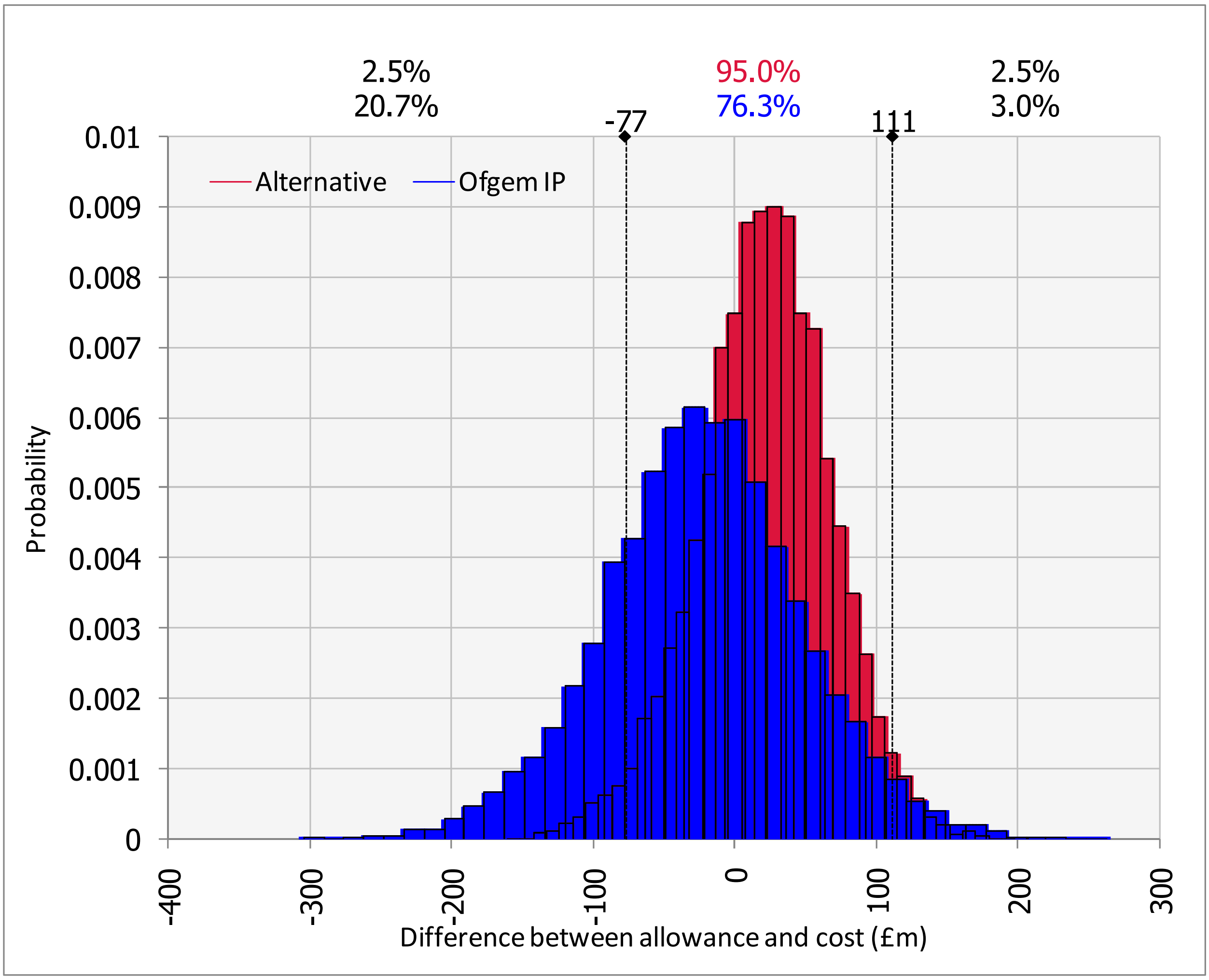
Revised assessment results

57 The forecast volume of generation connected in RIIO-T1 is shown in the graph below.



58 The distribution has a mean of 25.4GW (compared to a Gone Green value of 25.7GW and a Slow Progression value of 26.1GW) and 95% confidence intervals of 19.2GW to 31.6GW.

59 The difference between the cost and the allowance (adjusted by the uncertainty mechanism) for the national volume-driver described in Ofgem's Initial Proposals and the zonal volume-driver described as our alternative approach is shown in the graph below.



60 The graph shows that the zonal alternative approach is more accurate than the national volume-driver described in Ofgem's initial proposals, with a significantly lower standard deviation. The results are summarised in Table 8 below.

Table 8 – Probabilistic comparison of uncertainty mechanisms

	Ofgem Initial Proposals	NG Alternative
Mean	-£22.4m	£21.7m
Standard deviation	£69.9m	£46.8m
Minimum	-£303.9m	-£160.0m
Maximum	£262.7m	£207m

61 The results show that the National Grid alternative provides a lower risk solution for both National Grid and consumers.

62 The mean result is -£22.4m with the Ofgem approach and £21.7m with the National Grid alternative. Since the mean new generation connection volume is lower than the baseline, this suggests that the Ofgem proposal claws back too much of the base funding whereas the National Grid alternative does not quite claw back enough. It is likely that the accuracy of the National Grid model could be improved by banding the unit cost allowances for certain zones, but this would come at the cost of additional complexity and loss of transparency.

Conclusions

63 We have carefully considered the issues highlighted by Ofgem with our local generation connection uncertainty mechanism proposals. We have also studied Ofgem's simplified approach to the local generation connection volume-driver which formed a part of their Initial Proposals.

64 We have developed an alternative approach which addresses the concerns raised by Ofgem regarding our March 2012 proposals.

65 This alternative approach is based on zonal unit cost allowances rather than a national average. We have assessed both approaches using deterministic and probabilistic analysis. The results show that our alternative approach is more accurate and provides improved protection for National Grid and consumers.