Review of PRRT Gas Pricing: Submission

References

1. This submission deals with the Questions set out in the April 2019 Consultation Paper for the Review of the PRRT Gas Transfer Pricing Arrangements, so when a question is referred to by number it is the numbering in that Consultation Paper that is intended.

2. This submission is informed by the Petroleum Resource Rent Tax Review (the Callaghan review), to which the review of PRRT gas pricing is a response. On some issues the Final Report of that review informs the meaning of questions set out in the Consultation Paper, and refers to or quotes from numbered sections of that Report.

The Author

3. The author of this submission is Christopher Lawson Hood. Mr Hood is a Chartered Tax Advisor, and was a solicitor in practice in Sydney before joining the ATO, where he was a legislative instructing officer who worked on the PRRT legislation when introduced and enacted, led all subsequent PRRT legislation and regulation measures, was the technical leader of PRRT administration, and led and instructed in all PRRT litigation, until leaving the ATO in April 2012 (as, at that time, a Senior Tax Counsel).

Reviewing PRRT Gas Pricing: framework

4. The gas pricing rules under the Petroleum Resource Rent Tax Assessment Regulations 2015 (the 2015 Regs), and their initial form in the Petroleum Resource Rent Tax Assessment Regulations 2005 (the 2005 Regs), have the same purpose and structural features. The gas pricing rules provide the basis on which the amount of assessable receipts for sales gas will be worked out, if the sales gas is used in integrated liquefaction and integrated (co-)generation operations.

5. The assessable receipts of a taxpayer with a petroleum project interest will include those sales gas receipts, where the petroleum project produces sales gas that is used in integrated liquefaction or integrated (co-)generation.

6. The petroleum project includes recovering petroleum from a production licence area, any production of marketable petroleum commodities from that petroleum, any storage of petroleum or of marketable petroleum commodities (up to the point where they are sold or are moved away from their place of production or from adjacent storage), and associated movement, connected services, related employee amenities, and environmental operations and facilities that are related to the project itself (Petroleum Resource Rent Tax Assessment Act 1987 (the PRRTAA) s19; in some circumstances production licences may be combined so as to provide for a single petroleum project in relation to production from all of them, PRRTAA s20, and special rules deal with 'tolling' of petroleum from other projects, or from other taxpayers interested in the same project, eg PRRTAA s24A.

7. However, there is only one petroleum project regardless how many different marketable petroleum commodities are produced from it. And the resource rent tax is worked out according to all the deductible expenditures, and all the assessable receipts, of that entire project, not commodity by commodity and not distinguishing tolling from other relevant expenditures and receipts.

8. This means that the extent of resource rent from the sales gas of a petroleum project that is employed in an integrated gas to liquid operation, or an integrated gas to electricity operation, is not worked out separately under the PRRTAA.

9. The 2005 Regs and the 2015 Regs work out the amount of the assessable receipts for sales gas used in an integrated gas to liquid operation, or in an integrated gas to electricity operation, according to three possible methods. There may be an advance pricing agreement (APA), which must be used if it exists[1]; there may be a comparable uncontrolled price (UCP), which must be used if it exists and there is no APA and no simplifying elections by all participants[2]; and the residual pricing method (RPM)[3], which allows for significant simplification by election of all integrated project participants[4].

RPM is not an estimate or allocation either of profit or of rent

10. The tenor of some submissions to the Callaghan review led to the Report describing the RPM, variously, as determining and then apportioning the resource rent from sales gas and its liquefaction in an integrated operation[5], and as determining and then apportioning the annual profit from sales gas and its liquefaction in an integrated operation[6]. These ways of thinking are understandable, as expressions of the broad economic effect of changes in the way of determining an assessable receipt. But they are misleading.

11. The RPM is doing something much simpler. It is comparing a current-year (or current period) set of simplified capital costs, apportioned to the period; pooled operating costs of the integrated operation in the period; and costs of the particular taxpayer in the period. These are then characterized as upstream or downstream as appropriate. For the upstream part of the integrated operation, these costs add to produce the 'cost plus' minimum value of sales gas of the PRRT project. For the downstream part of the integrated operation, these costs subtract from the value of final product (liquefied gas, or commercially supplied

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[1] Currently, 2015 Regs r19(2), r20(2)
[2] Currently, 2015 Regs r19(3), r20(3)
[3] Currently, 2015 Regs r19(5), r20(5)
[4] Currently, 2015 Regs r48, r50 for operations existing before 2 May 2010
[5] Callaghan review Report at 4.9: 'The purpose of the RPM is to allocate rents of overall gas-to-liquids (GTL) (normally LNG) operations, between the 'upstream' component (gas extraction to taxing point) and the 'downstream' component (taxing point to LNG production and export).'
[6] Callaghan review Report at 4.9: 'the RPM splits the overall profits from LNG between upstream and downstream operations'.

electricity) to produce the maximum value of sales gas of the PRRT project. What these measures express is, roughly, the costs that had to be commercially recovered to justify 'upstream' production of sales gas for the integrated operation, and 'downstream' liquefaction of the sales gas or commercial electricity production from it, as integrated operation continued during the year.

12. But these simplified methods do not arrive at a measure either of profit of the integrated project, or of total rent of the integrated operation, that is then apportioned or allocated to work out the assessable receipt of the PRRT project for sales gas taken by the integrated operation. Nor do they arrive at 'upstream' profit, 'upstream' rent, 'downstream' profit, or 'downstream' rent.

13. These methods do resemble the netback and cost-plus elements of the process by which, for instance, 'hub' pricing in the USA is commonly worked out. But there what is being worked out is the actual price to be paid by or to competing persons, one seeking to raise, the other to reduce, that price. In that context it is acutely relevant to each of them whether the costs netted back, or the costs added for cost-plus, are actually correct; and the competing persons have their costs arise independently, under different arrangements, and with all the practical administrative issues about whether costs are being measured comparably. In integrated GTL or GTE operations these issues do not arise in that way. The upstream and downstream participants are the same. The arrangements under which costs are incurred are the same. Any attempt to estimate or allocate the upstream costs on an inconsistent basis to that used for downstream costs would be obviously manipulative.

14. The presence of (accounting, or similar) profit of the period, or of economic rent worked out as attributable to a period, doesn't affect the operation of the RPM. The cost-plus and netback price elements are averaged whether there is an excess of netback over cost-plus or otherwise; as long as costs are being worked out in a consistent way, and allocated correctly to upstream and downstream or between phases – that is, using an objective allocation method according to the proportion of the petroleum in a phase that is going into the integrated GTL or GTE operation as compared to other PRRT project purposes – overstating or understating the relevant costs taken into account in the RPM won't much affect the assessable receipt of the PRRT project. This helps methods in working out and allocating costs of the integrated operation to be administrably robust and self-correcting. The resulting RPM receipt is not worked out as an allocation of accounting or notional profit or as an allocation of a hybrid rent attributed to a period.

15. The elements of cost taken into account for the RPM calculation include some adjustment to[7], as well as period allocation of[8], capital costs. These adjustments and period allocation have the effect that some likely differences in timing and amount of *capital* costs of the upstream and downstream parts of the

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[7] 2015 Regs r37 uplifts certain pre-1-July-2012 costs to that date, and certain pre-2-May-2010 costs to their depreciated replacement cost on 1 May 2010.
[8] 2015 Regs r39, r40, r41, r42

integrated GTL or GTE operation are ameliorated. But they do not replicate the uplift used in relation to PRRT deductible expenditure both to maintain its real value and to ascribe a minimum rate of return which must be made before the expenditure is fully recovered from assessable receipts and PRRT can then arise. In the context of the PRRT itself there is no capital/revenue distinction; no such distinction is used in relation to uplift; and there is no attempt to use a method which, in substance, would allocate likely lifetime taxable rent or PRRT liability across periods – PRRT arises according to the whole of PRRT project assessable receipts and deductible expenditures to the end of the PRRT year across the whole life of the petroleum project.

16. Although the RPM broadly takes account of the minimum price 'upstream' costs require, and the maximum price 'downstream' costs can bear, it does not do so in an economically rigid fashion. Costs are not limited to 'marginal' production costs only, as purist economic theory might support. Instead a broad range of costs of the integrated operation allows for capital costs, using familiar income tax references (to costs of depreciating assets and to 'five year deduction' capital costs), and treating pre-production costs as capital costs too[9]. This means that the RPM approximates the costs taken into account in practical commercial decisions to continue to produce sales gas, or to continue to liquefy sales gas or produce electricity commercially from it, in a way more consistent with the way commercial decisions are undertaken.

Specific cost provisions in the RPM

17. The specific cost provisions of the RPM each express a current policy, working out the general principles of year-by-year sales gas valuation. The costs associated with an integrated GTL or GTE operation include costs that are only indirectly attributable to the integrated operation (where the PRRTAA identifies as deductible expenditure only directly attributable items); and the costs are expressly apportionable[10]. The integrated operation and its upstream and downstream stages are a set of production actions, set out clearly as such[11].

18. Some costs are excluded from the RPM calculation. These include payments between integrated operation participants[12], exploration costs[13], pre-production feasibility or environmental costs[14], cost of removing integrated GTL infrastructure[15], environmental or site restoration costs[16], and financing costs, equity raising costs, costs of acquiring interests in existing petroleum projects or associated permits or in their profits, receipts or expenditures, and payments of

[9] 23015 Regs r36 (1)(b)
[10] 2015 Regs r31(2), (4) and (5)
[11] 2015 Regs r8
[12] 2015 Regs r31(3)
[13] 2015 Regs para 32(a)
[14] 2015 Regs para 32(b)
[15] 2015 Regs para 32(c)
[16] 2015 Regs para 32(d)

tax[17], and personal costs of other participants[18]. These can each be understood as not costs of the integrated operation itself; and without exclusion, some of them might come in by indirect attribution. Personal costs are, in substance, costs of an integrated operation participant dealing individually with their own share of output in kind; so where other integrated operation costs are pooled and shared according to share of output personal costs are particular to the individual participant and taken into account wholly, but only, in relation to that participant.

19. Payments between integrated operation participants do not change the 'pool' of costs of the integrated operation and should be excluded for that reason. Exploration costs are not costs affecting the decision to continue to produce sales gas, or to continue to liquefy it or use it for commercial electricity production, and should be excluded for that reason, and pre-production feasibility or environmental costs should be excluded on the same basis. Costs of removing integrated GTL infrastructure are not costs relevant to deciding to continue the integrated operation, or if they are they are costs which encourage continued operation by falling due only as operations are discontinued, and so should be excluded from the RPM calculation, and environmental or site restoration costs should be excluded on the same basis. Financing and equity raising costs are not costs relevant to the decision to continue integrated operations – if the operation cannot cover such costs this affects the position of its current participants but not the decision to continue integrated operations, and it is expensive and difficult to separate financing and equity raising for the integrated operations from financing and equity raising for the PRRT petroleum project and from other downstream activities in any consistent and verifiable fashion. Costs of acquiring interests in existing petroleum projects or associated permits or interests in their profits, receipts or expenditures, and payments of tax, are correspondingly not costs relevant to the decision to continue integrated operations in the current year, and should be excluded on that basis.

20. Direct costs are wholly and directly attributable to production, transport, storage, marketing or selling of the integrated operation[19]. They are wholly attributable to upstream or to downstream stages, or (above a threshold) are reasonably apportioned into separate upstream and downstream direct costs.

21. Personal costs are the costs of marketing and selling project liquid (liquefied gas from the integrated operation) or project electricity (commercial electricity generated by the integrated operation) by the particular participant in the operation[20].

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[17] 2015 Regs para 32(e), collectively referring to PRRTAA paras 44(1)(a) to (h)
[18] 2015 Regs r34
[19] 2015 Regs r33 (2), (3) and (4); r33(7) sets the threshold for apportionment into separate upstream and downstream costs
[20] 2015 Regs r33 (6)

22. Indirect costs are costs of the integrated operation which are not direct costs[21].

23. Capital costs can't be personal costs, and must be costs from before the production date, costs of depreciating assets, or costs eligible for five-year write off under s40-840 ITAA 1997[22]. These are both uplifted, essentially maintaining their real value over time, and allocated over their operating life or appropriate period in working out the RPM year by year[23]. Operating costs are all other costs that aren't personal costs[24]. They are taken into account in working out the RPM in the year they are incurred; they are not augmented or allocated to other years. Personal costs are also taken into account in working out the RPM in the year they are incurred.

24. The reasonable apportionment of costs between the integrated operation and other purposes is made in different ways in different circumstances. The most important feature of apportionment for these purposes is that it is based on relative volumes of the petroleum stream for those purposes at various points, not on relative values of the petroleum stream. Broadly, the concept of phase points where it is used is a working out of this key principle[25].

Question 1 – principles for assessable receipts; question 8 - issues

25. The principles which should underpin the ascertainment of the assessable receipts for feedstock gas in integrated operations, going forward, should continue to be the same as at present. The assessable receipts for feedstock gas are and should be a share of the total value of the product of the integrated operations, worked out according to a method balancing the costs of the upstream and downstream parts of the operation.

26. The ascertainment of the assessable receipts for feedstock gas in integrated operations should not be based on an identification and allocation of either total rent of the integrated operation, or of total current-year profit of the integrated operation. Nor should those receipts be ascertained so as to maximize PRRT of the petroleum project which includes the upstream part of the integrated operations.

27. Some case study modelling and submissions assert that the RPM is flawed as a method. This modelling and these submissions are based on the contention that the ascertainment of assessable receipts for feedstock should directly deliver the measurement of rent subject to PRRT, or should increase the measure of that rent, by reference to public policy ('fair share') arguments. This

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[21] 2015 Regs r33(5); these include a broad range of overhead costs of kinds that are not distinctly applicable to upstream or downstream (or to particular phases within upstream or downstream) operations

[22] 2015 Regs r36(1)

[23] 2015 Regs r39, 40, 41 and 42

[24] 2015 Regs r 36(3)

[25] See most simply 2015 Regs r43

modelling and these submissions are based on an imprecise understanding of the role of the GTP regulations in the operation of the PRRT. In particular, analysis that depends on characterizing the RPM as an 'allocation' of 'profit' of the integrated operations would require the RPM to change to a systematic measure of profit. Yet neither for income tax nor for resource rent tax purposes is the integrated operation normally accounted for by the industry as a separate entity; there are no inherent balances between competing reasons to over and to understate cost measures for the project; there is no reason for the industry to avoid estimating costs in such a way as to eliminate or minimise any excess of netback price over cost-plus price[26], and the administrative cost and uncertainty of changing the RPM framework so as to depend on accurate ascertainment of annual profit of the integrated operations would be very high without any probability of higher assessable receipts for feedstock gas.

28. The particular option discussed in the Callaghan report at 4.9.3 essentially assumes that an RPM ascertains an overall excess return from integrated operations and allocates that return entirely to the PRRT project, that is, upstream. This is implausible. In effect it shifts the taxing point for integrated operations to the end of those operations – but without treating the relevant downstream costs as deductible expenditures, subject to the augmentation required under the PRRT; and treating the rough costs compared by netback and cost-plus RPM elements as the same thing as the deductible expenditures for PRRT purposes. They aren't the same and in many respects are not comparable. Neither 'period' allocation nor capital/operating distinctions are part of the PRRT; and indirect costs readily used in the RPM are excluded from PRRT calculation. Figure 4.8 Netback Only from the Callaghan report is no more than an illustration that if the RPM measure of assessable receipts is substantially enlarged PRRT collections will correspondingly rise. This is, of course, true of any method that raises PRRT assessable receipts while leaving deductible expenditures unchanged.

29. Accordingly there are none of the issues raised in question 8, or other such issues, that should be taken into account in ascertaining the assessable receipts for feedstock gas.

Questions 2, 3 and 4 – CUP for assessable receipts

30. The RPM's definition and use of the CUP concept is flexible and consistent with the application of the OECD Guidelines. No significant change to the drafting of the RPM in these respects is warranted.

[26] IMF mission reports for many countries show instances of mining operations that report no profits, and pay little or no taxes, though continuing in expanding operation for decades. One instance from public mission reports is gold mining production in Tanzania; see *Tanzania: Mining and General Tax Policy*, Krelove, Watson, Luca and Hood, IMF Fiscal Affairs Department, 2011.

31. The CUP in the RPM must be used if it can be, absent an advance pricing agreement[27]. What a CUP is is not a mechanical or rigid definition, which might fail to be satisfied on narrow technical grounds. Rather, a CUP exists if the Commissioner of Taxation is satisfied that there was a sale in a relevant market, and that this was at an observable arm's length price[28]. Factors in working out whether there is a relevant market must include those set out in the Regulations[29], but should not be read as limited to those factors. Although the meaning of 'observable arm's length price' is not defined, a non-arm's length transaction is one where parties are not dealing with each other at arm's length in relation to the transaction, whether by reason of connection between the parties or any other reason[30], and an observable arm's length price would draw meaning from that context. The Callaghan review recommendation appears to express the consequence of the existing ascertainment of sales gas assessable receipts, when that recommendation calls for regular consideration of whether an industry-wide CUP is available in preference to use of the RPM method.

32. The OECD Guidelines in various areas can readily inform the Commissioner as to whether a price is an observable arm's length price. They would not decide the issue. However, those Guidelines discussed in the Consultation Paper contemplate treating elements of a single taxpayer or group as if they were independent parties, for the purpose of testing transfers between them and whether these are at arm's length rates. As the ascertainment of assessable receipts for sales gas used in integrated operations does not involve transfers at all, methods of testing the terms of transfers between more or less associated parties have no potential for use there. It is in testing the terms on which the output of the integrated operations are sold that these OECD guidelines may be most useful; in this respect there is no impediment to their use that needs adjustment or removal.

Question 5 – observable tolling fee

33. Use of an observable tolling fee under the current RPM is straightforward. The observable tolling fee if charged to participants in the integrated operations would be part of their costs; it would not be a basis for comparison.

34. Comparison to observable tolling fees would be part of verifying the costs used in the RPM calculation. It does not require a special rule. However, more widely, there is some question whether the current terms of Division 6 of the PRRTAA, whether in relation to 'schemes' or in relation to non-arm's-length expenditures, apply to the ascertainment of costs for the purposes of the RPM. If this were clarified, the use of observable tolling fees would be one of many areas where comparisons might assist in verifying costs.

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[27] 2015 Regs r20 (3), (4) and 21(3), (4); note the general rule that actual sale price is used where higher than what would otherwise be the RPM amount

[28] 2015 Regs r23(1) and (2)

[29] 2015 Regs r23(3) and (4)

[30] 2015 Regs r12

Question 6 – netback of arm's length marketing, shipping and tolling

35. A CUP for costs, either relevant to netback, or more widely, could be expressed. The particular concept in question 6 is, in effect, a comparison between netback of actual costs, and netback of arm's length marketing, shipping and tolling, where those arm's length marketing, shipping and tolling prices can be ascertained. This is a special case of requiring costs to be no more than arm's length, as well as to be verified. If cost verification clearly includes an arm's length upper limit to costs taken into account for RPM, the special concept in question 6 would not be required or appropriate. However, the asymmetry of using only netback where netback is less than cost-plus should be removed; where integrated operations continue, any shortfall in meeting both the cost-plus costs and the netback costs should fall equally on upstream and downstream, as any excess does.

Question 7 – future projects depending on third party access

36. This question is a matter for industry and Departmental input.

Question 9 – including exploration and additional development costs in upstream

37. The framework for ascertaining assessable receipts from feedstock gas in integrated operations presently excludes exploration and a range of project development costs. If these were included, they would require apportionment – there is no suggested justification (other than PRRT maximization) for attributing them solely to upstream costs. Exploration, and the currently disregarded project development costs, are relevant to integrated operations in the same way as to any other PRRT project and downstream operations. Were an attribution to be made, this would need to be on a set basis – as with the present RPM, I would think it essential that attribution be on the basis of product volumes (perhaps using phase points and contained energy calculation, as at present) and not on the basis of product values.

38. The reasons for contemplating this expansion of the costs taken into account in RPM calculation seems to be to increase cost-plus costs without any commensurate increase in netback costs, that is, to increase assessable receipts under the RPM. However this is inconsistent with the broad basis of attribution discussed above, and the principles behind it. In working out how much the cost-plus must recover to justify continuing to put sales gas up for liquefaction or for commercial electricity production, and comparing this with how much netback must recover to justify continuing liquefaction or commercial electricity production from that gas, in an integrated operation, the general sunk costs of exploration and of wider petroleum project development are not relevant to the current-year calculation of assessable receipts.

Question 10 – depreciating assets for use in production before integrated operation

39. Where capital costs are partly written down for use before integrated operation begins, this reflects that those costs are only partly costs of the integrated operation. The effect is the same where the costs relate to other uses during the period of the integrated operation – in that case only so much of the

costs as relates to the integrated operation is taken into account in working out amounts for the RPM. The same principles apply to the downstream as to the upstream costs; just as some capital costs downstream relate to other production of marketable commodities, capital costs upstream are apt to relate to costs of liquefaction or commercial electricity production from gas that has not come from the integrated project.

40. The discussion in the Consultation Paper seems to me to reflect difficulty with the augmentation, reduction and allocation rules for capital costs. But any change would require a comparably complex approach.

41. Notional cost as at the beginning of use in the integrated operations still leaves the necessity of taking out use of capital costs for other purposes during the period of the integrated operations. I doubt the benefit of any change.

Questions 11, 12, 13 – capital allowance rate

42. Using a common capital allowance without regard to the extent of upstream or of downstream use simplifies the practical operation of the provisions. As the Consultation paper notes, increasing the capital allowance rate will reduce the netback price and raise the cost-plus price; if asymmetry here is removed this is of little moment.

43. The degree of risk either in the PRRT project or in the integrated operation is uncertain and difficult to measure reliably even in hindsight, after conclusion of the project and all operations. At all earlier points the degree of risk is incapable of workable application to produce different allowance rates. It is unworkable as a source of distinction between either the PRRT project and the integrated operations, or between the upstream and downstream components of the integrated operations.

Question 14 – changing the profit split when LNG and electricity price is high

44. Under the RPM, the netback is from the value of the output of the integrated operations. As that value rises, the netback price rises to that extent (except so far as higher netback costs are actually incurred, say to increase output).

45. This question assumes, and requires, that costs used in the RPM be minimised and so that netback and cost-plus elements be correct. Then the allocation between upstream and downstream of the excess of netback over cost-plus arises (in most cases – continued integrated operation suggests that all costs must be more than covered).

46. However, there is still no suggestion of a reason, other than revenue maximization, for attributing the excess other than equally. The suggestion in some submissions to the Callaghan review that the taxing point for PRRT extend to the output of any integrated operation would, properly, bring in as deductible expenditures the qualifying downstream costs of integrated operation; and this would apply the appropriate augmentation to those deductible expenditures.

Adjusting the split between upstream and downstream lacks this consistency with the principles of ascertainment of PRRT. The comparisons to Qatari returns from gas liquefaction is unfavourable to Australia, but this is entirely because Australia's royalty or equivalent rates are so much lower. It is there, not in the split between upstream and downstream sales gas pricing, that change should be considered.

Questions 15, 16, 17, 18

47. I have no additional comment on these questions.

Question 19 - APAs

48. The lack of any APAs suggests that there have been no compelling costs of applying the RPM sufficient to encourage participants in integrated operations to put their information before the Commissioner and seek a substitute, whether an actual price or a more convenient method of ascertainment. However there are no restrictions or limitations that materially affect participants seeking an APA[31]. I do not consider that the availability of an APA should be further narrowed; at present, practical and commercial reasons of all kinds might justify and support seeking and obtaining an APA.

Questions 20, 21, and 22 – transparency, simplicity, fair return: between participants and for the Australian community

49. The present structure of the regulation reflects the PRRT itself. Different participants may have different interests; knowledge about costs and about assessable receipts may have a degree of commercial confidentiality to each of them. Presently the RPM pools capital and operating costs of the integrated operations while keeping individual the personal costs for each participant of dealing with the share of natural gas or sales gas to which they are individually entitled.

50. Any change to the entitlement of participants to information each from another should be consistent with wider change to the PRRTAA in that respect.

51. Any publication of the assessable receipts from feedstock gas could not describe transparently the resource rent for integrated operations. PRRT is not imposed independently for those operations, as distinct from all other parts of the PRRT project and its marketable petroleum commodities (and their internal transport and adjacent storage). If there is to be greater transparency about PRRT, it needs to be under the PRRTAA and in relation to the whole PRRT project. I do not consider that persuasive transparency about integrated liquefaction or commercial electricity production in gas operations is possible as an independent feature.

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[31] 2015 Regs r22

Contact, clarification and discussion

52. I am happy to be contacted for clarification or discussion. I am also willing to discuss issues with others who have made submissions, or to discuss further issues or further options for change.

Christopher Hood CTA

[redacted]

[redacted]