PO Box 3150

Weston Creek, ACT 2611

28 July 2017

Manager

Large Corporates Unit

Corporate and International Tax Division

The Treasury

Langton Crescent

PARKES ACT 2600

Dear Sir/Madam

**SUBMISSION: OPTIONS TO ADDRESS THE DESIGN ISSUES IDENTIFIED IN THE PETROLEUM RESOURCE RENT TAX (CALLAGHAN) REVIEW**

Please find attached suggested redesign of the four aspects of PRRT design identified by the Treasury options paper from the Part A recommendations of the Callaghan review.

The suggested redesign focusses particularly on bringing together design of uplifts, order of deductions and transferability of exploration expenditure in a way that provides simple, consistent treatment that meets the overarching objectives of appropriate return to the community and minimal distortion of investment in the petroleum resource sector.

Yours faithfully

Wayne Mayo

Tax Consultant

**DESIGN FEATURES OF REDESIGNED PETROLEUM RESOURCE RENT TAX (PRRT)**

The following table responds to the four aspects of PRRT design identified by the Treasury options paper from the Part A recommendations of the Callaghan review, as well as the issue of definition of new projects discussed in the options paper.

|  |  |  |
| --- | --- | --- |
| **Design Feature** | **Suggested Redesign** | **Comment** |
| **1. Uplift Rates** | | |
| Exploration expenditure uplift | LTBR\* x 1.5 within 5 years of production licence or of transfer to profitable project.  GDP deflator before that 5-year period. | Multiplicative, rather than additive, design accommodates changing levels of LTBR over time.  Multiplier of 1.5 recognises higher risk (than during production phase) of deductions being lost completely after unsuccessful exploration – despite transferability provisions.  Sound exploration decisions factor in the high probability of no success and nil return along with probability of success and associated reduced project risk during production phase.  GDP deflator recognises potential tax revenue risk from many years of applying high uplift. |
| General expenditure | LTBR  \*Strictly, to achieve tax neutrality after both PRRT and income tax, LTBR should be at after-income tax level with post-PRRT flows (costs/receipts reduced by PRRT tax rate) feeding into income taxation (like GST design). | LTBR reflects the much reduced risk of losing deductions during production and closing-down phases.  As the Callaghan report notes (pg 72), “..once developed, rare would be the (still risky) project that could not utilise PRRT deductions uplifted at LTBR.”  Simplicity is achieved with same uplift rate applying to any general expenditure before production licence.  Attached illustration shows how tax neutrality achieved with marginal project when LTBR uplift differs from investor’s discount rate – consistent with Box 4.1, pg 73, of the Callaghan report and showing the ‘circularity’ issue identified in options paper (pg 6) of higher uplift leading to greater chance of losing uplifted deductions. |
| **2. Changes to order of deductions** | | |
| Ordering principle for different expenditures | Once project established (production licence applied for), all prior uplifted project expenditure collapsed into one project pool and uplifted at LTBR | With risk of losing deductions much reduced, there is no justification for continuing to uplift project expenditures above the rate for general expenditure.  With all project expenditures then uplifted at LTBR (including any prior exploration expenditures attracting GDP uplift and resource tax expenditure), ordering of deductions is no longer an issue.  Once project commences, associated exploration expenditure (in related exploration permit area) is no longer transferable to other projects.  Redesign is consistent with project-based PRRT design with transferability added to accommodate stranded (non-project) exploration expenditure. |
| **3. Transferability** | | |
| Exploration deduction transfer | Exploration expenditure only transferable before any associated project is established | Before 1991 amendments allowing transferability, exploration expenditure not associated with a PRRT project was stranded.  The suggested redesign of ordering of deductions and transferability would continue to reduce the risk of stranded exploration deductions while maintaining the project basis of PRRT design.  In options paper’s Green Project illustration (Box 1, pg 14), suggested design changes have the following effects on each participant’s $100m of exploration expenditure: Company A’s transfer in 2017-18 (before Project Green’s production licence) unchanged as Project White is profitable in that year; and Company B, C and D’s expenditure is uplifted at LTBR from 2019-20 within Project Green (Blue and Red projects are not profitable before Project Green’s production licence in 2019-20). |
| **4. Gas Transfer Pricing** | | |
| Taxing point | In absence of clear, transparent and prioritised comparable uncontrolled price (CUP) for sales gas in integrated LNG operations, there would be many advantages in moving PRRT taxing point to end of LNG production (then a process that produces a ‘marketable petroleum product’) | A clear, transparent CUP for gas in integrated LNG operations prioritised over other transfer pricing methodologies would meet PRRT requirements directly, but practical difficulties remain.  If pricing of such gas via the widely-applied residual pricing methodology (RPM) is retained, modification is essential to address complexities, inconsistencies and arbitrary outcomes but shortcomings would no doubt remain and RPM would exhibit structural rigidities, such as: if the same effective life for capital allocation applies upstream and downstream of gas pricing point, gross LNG receipts (driving economic rent) will be split equally upstream and downstream regardless of the level of the common capital allowance rate specified.  Netback pricing methodology would overcome many of the shortcomings of the RPM but the key return to downstream (LNG) capital resulting from required computations (a sub-set of those in RPM) would invariably differ significantly from the return specified – though in some circumstances a ‘break-even’ result could occur whereby investors are indifferent to having taxing point at the wellhead or end of LNG production.  Moving taxing point to end LNG production would remove complexities and uncertainties associated with the RPM and netback methodologies.  While any economic rent associated with downstream (LNG) production could be captured if taxing point were moved, it is the gas resource that underpins overall economic rent.  A well-designed PRRT with taxing point at end LNG production should have little or no impact on LNG investment decisions even though any economic rent associated with LNG technology may be taxed. |
| **5. What is a new project?** | | |
| Can old/new distinction be avoided? | Options like restricting changed design, where possible, to expenditure after a future date or even some reduction in the PRRT rate (with accompanying increase in capital value of existing projects) would be worth considering if they offered the prospect of existing projects transitioning into a redesigned system. | A distinction between new and old projects would involve much complexity and investment uncertainty – as reflected in the issues discussed in the options paper concerning project combination and exploration expenditure transfer.  Such distinction would raise many difficult issues in relation to gas projects using shared facilities.  While the Callaghan review was rightly most concerned not to impose design change on existing projects – in recognition of sovereign risk effects – considerable reduction in compliance and administration costs would be realised, with positive spin-offs to investment decision-making, if the transitioning of existing projects to a simpler, more certain and less distortive single PRRT regime could be achieved. |

**ATTACHMENT: PRRT NEUTRALITY WHEN UPLIFT RATE DIFFERS FROM HURDLE RATE**

The analysis of a stylised petroleum project in this attachment is equivalent to that of the two-year project in Box 4.1, page 73 in the Callaghan report.

**Pure cash flow taxation**

Table 1 shows how a pure cash flow (or Brown) tax bites only on above-normal profits perceived by an investor in the production phase of a proposed petroleum project. The table has the investor using a 15% risk-weighted discount rate to assess the viability of the highly stylised project. Thus, this investor requires at least 15% pa return from expected cash flows of the prospective petroleum investment (which equates to zero NPV with discount rate matching that return).

**TABLE 1**

Cash flows of stylised petroleum project subject to 40% cash flow tax (a)

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Year** | **Capital expenditure**  **(b)**  **$m** | **Net receipts**  **(c)**  **$m** | **Pre-tax cash flow**  **(d)**  **$m** | **Cash flow tax rebates/tax payments (e)**  **$m** | **Post-tax cash flow**  **(f)**  **$m** |
| **0** | 1000 |  | -1000 | -400 (g) | -600 |
| **1** |  |  | 0 | 0 | 0 |
| **2** |  |  | 0 | 0 | 0 |
| **3** |  | 780 | 780 | 312 | 468 |
| **4** |  | 662 | 662 | 265 | 397 |
| **5** |  | 219 | 219 | 88 | 131 |
| **NPV @ 15%** |  |  | **Zero (h)** | **Zero** | **Zero (h)** |
| **NPV @ 5%** |  |  | **390 (h)** | **156** | **234 (h)** |
| **IRR % (i)** |  |  | **15** | **15** | **15** |

1. Immediate expensing of all costs and immediate cash rebates for tax losses, so that negative cash flow is cut by 40% rebate and positive cash flow is reduced by 40% tax.
2. Only capital expenditure involved is $1000m up front.
3. Gross receipts from product sale less operating costs.
4. Column (c) less Column (b).
5. Pre-tax cash flow times tax rate (40%).
6. Pre-tax cash flow less (negative) cash rebate and (positive) tax payments.
7. Cash rebate equal to 40% of $1000m annual cash outflow.
8. Regardless of investor’s discount rate (unchanged after the tax), post-tax NPV equals pre-tax NPV cut by 40% (the tax rate).
9. The project’s pre-tax 15% internal rate of return (the interest rate that produces a zero NPV for the project) is unaffected by cash flow taxation.

Table 1 illustrates the situation where the project is of marginal viability before tax because the 15% pa before tax return it is offering (Column (d)) just matches the investor’s hurdle rate (and pre-tax NPV is zero with discounting at the hurdle rate). The project’s 15% pa pre-tax return comes from $1000m of general expenditure at start Year 1 (Year 0) followed by a characteristic time lag (when further expenditures would be made in practice) before realisation of delayed net receipts (sales revenue less operating costs, including closing-down expenditure) in Years 3, 4 and 5. The petroleum assets are scrapped for nil value at end Year 5.

Table 1 also shows the effect of imposing a 40% cash flow tax on the project. Under the tax, the investor receives cash payments that cut negative cash flows by 40% and pays tax at 40% on positive cash flows (Column (e)). With all negative and positive cash flows cut by 40%, post-tax cash flow in Table 1 (last column) still provides the investor with a 15% return after tax (and again zero NPV with discounting at the investor’s unchanged discount rate).

With the petroleum project subject to 40% cash flow tax, this investor looking at the stream of government cash rebates in Year 0 and tax payments in Years 3, 4 and 5 (Column (e)) finds that no tax is paid in discounted terms. Tax payments associated with the investment (in its later years) discounted at 15% just balance the up-front $400m cash rebate to provide a zero NPV. But were the investment to earn more than 15% – earning above-normal profits from the investor's point of view – the investor would then see government taking out more than it put in. Similarly, Table 1 shows that, if the investor uses a 5% discount rate rather than 15%, the investor would view the project’s tax payments as exceeding the early cash rebate by $156m in discounted terms (reducing $390m pre-tax NPV by that amount to $234m after tax). Above-normal profits perceived by the investor (profit above the investor’s 5% required return) would be seen by the investor as being subject to tax.

Economic rent (or above-normal profit more generally) is in the eye of the investor and the inherent design of cash flow taxation allows that personal view of economic rent to play out.

**PRRT with 5% uplift rate reflecting minimal risk of losing deductions**

Table 2 applies the PRRT to the project in Table 1 with loss uplift rate for general expenditures set at LTBR of 5%, the rate consistent with negligible risk of losing carried-forward losses in the production phase. In contrast to outcomes in Table 1 under full loss offset, in Table 2 (where losses are carried forward at 5% pa) the project after tax has an overall return of 11.5% pa and NPV of -$104m with discounting at 15% (Column (f)). Taken on face value, these post-tax results show 15% pre-tax return reduced to 11.5% and zero NPV turned negative for the investor with a 15% discount rate. These outcomes suggest the project, marginal before tax, has been made sub-marginal by the imposition of PRRT with 5% uplift rate.

The problem with this interpretation of post-tax cash flows is that overall post-PRRT cash flows in Column (f) contain a mixture of two cash flows with very different risks. Table 1 splits aggregated post-tax flows of Column (f) into these two flows exhibiting very different risks: in Column (g), those possible post-tax flows with a wide range of project risks justifying a 15% hurdle rate (pre-tax flows all cut 40% by the Brown tax effect, matching the flows in the last column of Table 1); and, in Column (h), those flows that involve minimal risk. The flows in Column (h) are a minimal-risk asset to the investor because there is minimal risk of not being able to offset PRRT losses uplifted at 5% against the project’s net receipts. This minimal-risk asset comprises the forgoing under the PRRT of the up-front shortfall in cash rebates of a Brown tax, in the knowledge that there is minimal risk that the amount forgone up front will not be repaid with interest (uplift) via later tax payments reduced below those payable under a Brown tax (with LTBR uplift rate reflecting these circumstances where it is just a matter of time before the shortfall is repaid).

The minimal-risk asset in Column (h) is computed in Table 2 simply from the difference between aggregated post-PRRT cash flow in Column (f) and alternative post-Brown tax cash flow in Column (g). The deficiency of $400m in Year 0 from lack of cash rebates under PRRT is shown in Column (h) to be fully recovered via lower tax payments (relative to cash flow taxation) of $312m in Year 3 (where nil PRRT is paid versus $312m, or $780m x 0.4, Brown tax) and $159m in Year 4 ($106m PRRT paid versus $265m, or $662m x 0.4, Brown tax). These lower tax payments arise because the PRRT loss associated with the $1000m up-front outlay is compounded forward at 5% and offset against project net receipts in those years. What would have been a $400m cash rebate in Year 0 under pure cash flow taxation becomes $312m and $159m of lower tax payments in Years 3 and 4, respectively.

**TABLE 2**

Cash flows of stylised petroleum project subject to 40% PRRT (a)

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Year** | **Capital expenditure**  **(b)**  **$m** | **Net receipts**  **(b)**  **$m** | **Pre-tax cash flow**  **(c)**  **$m** | **Base after loss uplift**  **(d)**  **$m** | **PRRT payments**  **(e)**  **$m** | **Post-tax cash flow**  **(f)**  **$m** | **Cash flow after pure cash flow tax**  **(g)**  **$m** | **Cash flow (f) less (g)**  **(low-risk asset)**  **(h)**  **$m** |
| **0** | 1000 |  | -1000 | -1000 |  | -1000 | -600 | -400 |
| **1** |  |  | 0 | -1050 |  | 0 | 0 | 0 |
| **2** |  |  | 0 | -1103 |  | 0 | 0 | 0 |
| **3** |  | 780 | 780 | -378 |  | 780 | 468 | 312 |
| **4** |  | 662 | 662 | 265 | 106 | 556 | 397 | 159 |
| **5** |  | 219 | 219 | 219 | 88 | 131 | 131 | 0 |
| **NPV@15%** |  |  | **Zero** |  |  | **-104 (i)** | **Zero (j)** | **-104 (i)** |
| **NPV@5%** |  |  | **390 (k)** |  |  | **234 (k)** | **234 (j)** | **Zero (k)** |
| **IRR % pa** |  |  | **15** |  |  | **11.5 (l)** | **15 (l)** | **5 (l)** |

1. Immediate expensing of all costs, tax losses (negative cash flow) compounded forward with 5% (LTBR) uplift.
2. As in Table 1.
3. As in Table 1.
4. Prior year negative cash flow uplifted by 5% plus pre-tax cash flow each year.
5. 40% times any positive tax base after loss uplift (Column (d)).
6. Pre-tax cash flow less tax payments in Column (e).
7. Pre-tax cash flow in Column (c) times 60% or the cash flow (see Table 1) that would have resulted from a 40% pure cash flow tax reducing all positive and negative cash flows immediately by 40%. These cash flows are the component of the project's overall post-tax cash flows in Column (f) that reflect project risk and are the same as Column (f), Table 1.
8. Overall post-tax cash flow less post-tax cash flow if a pure cash flow tax were applying – that is, Column (f) less Column (g). These cash flows comprise the minimal-risk component of the project's overall post-tax cash flows in Column (f).
9. Aggregate post-tax cash flow in Column (f) has negative NPV with discounting at 15%. However, this is seen to arise solely from discounting the minimal-risk component in Column (h) at 15% instead of 5% LTBR rate.
10. NPV of the project’s risky post-tax flows is 60% of pre-tax NPV, matching effect in Table 1 under immediate full loss offset.
11. With discounting at 5% LTBR, NPV of overall post-tax cash flow is also 60% of pre-tax NPV. That is because the minimal-risk component of project cash flows has zero NPV at this discount rate (discount rate matches loss uplift rate).
12. The internal rate of return (IRR) of overall post-tax cash flow is reduced below pre-tax return. As with NPV, however, separating aggregate post-tax cash flows into those related to project risk (Column (g)) and those with minimal-risk (Column (h)) results in IRR of the project-risk component being equal to pre-tax IRR and IRR of minimal-risk component equal to 5% uplift rate.

Because of the minimal risk involved with the cash flows in Column (h), it would be misleading financially for investors to discount them using a risk-weighted discount rate reflecting overall project risk. And, as shown in Table 2, the project’s post-tax NPV of -$104m for aggregated post-tax flows in Column (f) arises solely because the minimal-risk component of aggregated post-tax flows is discounted at a risk-weighted 15% – producing the -$104m in Column (h) – instead of 5%. Discounting those minimal-risk flows at 5% must result in zero NPV.

Consequently, with correct financial analysis and with 5% uplift rate aligned with risk of losing deductions, the project marginal before tax remains marginal after PRRT. In addition, PRRT is collected in Years 4 and 5.

Were the uplift rate set much higher at 15%, the investor using a 15% hurdle rate to discount aggregate post-PRRT flows would view the project as remaining marginal after tax – because no PRRT would be paid at all. The $1000m of up-front capital expenditure in Column (c), compounded forward at 15% pa, would be just fully absorbed by the last dollar of net receipts in Year 5 – with accompanying increased risk that insufficient net receipts would, in the event, be realised to absorb carried-forward losses completely (the ‘circularity’ issue noted in the Treasury options paper). Beyond this tax revenue difference even for marginal projects, the Callaghan review explains how excessively high uplift rates can significantly reduce and delay PRRT payments with above-marginal projects, particularly those that are capital intensive and have long lead times.