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Petroleum Resource Rent Tax Consultation Paper: Design Issues

The Australian Petroleum Production & Exploration Association (APPEA) is the peak national body representing companies engaged in oil and gas exploration and production in Australia. APPEA's members account for virtually all of Australia's oil and gas production and exploration. We welcome the opportunity to provide comments to Treasury on the recently released Petroleum Resource Rent Tax (PRRT) Consultation Paper ('the Paper').

Summary

Past investments in Australia's oil and gas industry have generated significant economic benefits for the nation. Industry investment has stimulated economic growth, employed many thousands of Australian workers, generated export income, supplied energy to businesses and households and led to the payment of significant sums of taxation to governments. The benefits from past investments will continue well into the future. However future investments are not guaranteed. Australia faces strong competition from other countries, while the costs associated with exploration and production in Australia continue to be high by world standards.

In terms of domestic gas production, more investment is required to meet demand - this is a time when market and regulatory reforms are essential. For export gas, existing liquefied natural gas infrastructure in Northern and Western Australia will shortly be seeking new supplies of gas to extend the life of plant and equipment. The use of this existing infrastructure generates both efficiency and cost benefits. Exploration must also be a key priority for industry and governments – today's exploration is tomorrow's production.

Energy policy in Australia has multiple dimensions and requires an approach that ensures individual policy settings are operating in a coordinated manner. Tax is one of the critical factors that will need to be addressed if Australia is to attain it broader energy policy goals.

The PRRT has been central to encouraging exploration and development of Australia's oil and gas resources. It has provided investors with an efficient taxation system that allows investors to achieve a risk adjusted return on invested funds before the imposition of a resource tax liability. It has been critical to Australia's success as a supplier of gas to domestic and worldwide markets.

The Paper raises key design and operational issues integral to the operation of the PRRT. Many of the provisions raised have been in place since the early 1990s, while others deal with important transitional matters following the decision to extend PRRT onshore and to the North West Shelf Project in 2012. Changes to the key design features of PRRT, if implemented, will impact on future exploration and development decisions (both onshore and offshore) in Australia. The Callaghan Review highlighted the importance of stability to investment decisions.

In APPEA's view, some comments in the paper either misunderstand the nature of the industry's operations or the objectives of the design of PRRT, or both. Some aspects of the discussion reflect the arguments put forward during the proposal to introduce the resource super profits tax in 2010, while others are inconsistent with the fundamental design principles of resource rent taxes.

Overall, the PRRT represents a balanced package of provisions. To view individual elements of the regime in isolation fails to recognise its truly integrated nature. Indeed, other elements of the regime, such as the very high tax rate and application of the GDP factor rules, should also be reviewed if such a line by line approach is adopted. Overall, APPEA does not consider a compelling case has been made for any significant changes, particularly as the impacts of ill-considered reforms can be long lasting and highly damaging to investment.

The comments below should be read in conjunction with our submission to the Callaghan Review Taskforce.

1 General Comments/Observations

The outcome of this review will be important, not just for companies engaged in oil and gas operations in Australia, but also for the place of gas in Australia's energy mix. No other energy producing industry in Australia is subject to such a high effective rate of tax. The community expects the industry to invest large sums of risk capital to both find and unlock our gas resources. It is critical this review is not undertaken in a policy vacuum.

As a general observation, the nature and tone of some of the commentary in the Paper is, in APPEA's view, conflicts with the general thrust of the observations contained in the Callaghan Report. In addition, there are comments framed around anecdotal views rather than being based on factual information.

Consultation Period

The Paper released by Treasury on 30 June 2017 provides very limited time for commentary on what, in many cases, are critical design features of the PRRT. While the industry supports the broad principle in the Callaghan Review Taskforce Report about the need to respect past investment decisions, issues and options raised in the Paper would, if implemented, have retrospective impacts on existing investments and are likely to jeopardise the development of resources.

APPEA is particularly concerned about the extremely short period of time provided to assess and comment on the highly complex issues associated with the gas transfer pricing methodology and the significant impacts that will arise for onshore exploration and development decisions in Australia if key aspects of Recommendation 2 from the Callaghan Report are implemented. More commentary on these matters is outlined below.

A Two Tier System – Is It Practical?

APPEA supports the need to ensure that past investments (including future extensions to existing projects as well as existing exploration permits and retention leases) are protected from retrospective law changes. The Paper envisages that this could be achieved by introducing a different set of provisions for new (largely undefined) investments. The practical implications of such a two-tier framework would need to be carefully considered to ensure that key design and operational features are not compromised. Any narrow grandfathering of existing permits (for example, those with production licences) at the expense of the substantial investments made in good faith in exploration permits and retention leases is not supported.

The Paper identifies wider deductibility as one important factor that would need to be considered, however the implications are likely to be far wider, particularly if, for example, different licences that form part of the one operation are treated differently for PRRT purposes. Careful consideration will need to be made of operational, compliance and investment impacts of any such dual regime.

Integrated Nature of the PRRT Provisions

The PRRT combines different provisions that, in some cases, have involved significant trade-offs – the tax represents an integrated package of measures. For example, the decision by the Government in 1990 to introduce wider deductibility for exploration costs was accompanied by a reduction in the carry forward rate for general projects costs. Similarly, the carry forward rate for exploration costs shifts from the long term bond rate plus 15 percentage points to the GDP factor rate when certain criteria are not satisfied. These represent a balance of measures.

The consultation questions in the Paper are often asked in isolation – they overly simplify the integrated nature of the tax. We consider such an approach has significant risks. Using the exploration example referenced above, an answer to the question of the appropriateness of the carry forward rate for exploration must be considered in the context of the operation of the five year GDP factor rule. This latter provision significantly disadvantages many projects that face delays for reasons that have little to do with the actions or decisions of investors.

Energy Policy Implications

This review must be undertaken with consideration given to the broader energy policy implications. Negative changes or restrictions on deductions will increase tax liabilities which must then flow through to higher development costs and higher prices to users. It should be noted that exploration is already at unsustainably low levels. Increasing the costs of development will compound this problem. Increasing prices for users runs counter to the Government's aim of putting downward pressure on rapidly rising energy prices. We note that these significant risks are not even acknowledged in the Paper. It is worthwhile remembering that the 1990 changes announced to PRRT by the then Government were considered in a wider energy policy content.

Gas projects (domestic, export or a combination thereof) require long lead times before they become profitable. Changes to the key provisions, under which it is determined when economic rent is generated, will place further impediments to project investment decisions – this will impact on both exploration and production. It will place pressure on the gas prices necessary to justify investments.

Understanding of PRRT

Recent discussions surrounding the operation of the PRRT have been characterised by a general lack of understanding of its general design features, how it operates and the ATO's administration of the law. In some cases, statements and comments have been made that have simply been incorrect. For example, incorrect suggestions that taxpayers have options of how or when deductions can be claimed or transferred or that there is a lack of administrative oversight and input into processes such as the gas transfer price methodology have not assisted an informed discussion.

In addition, APPEA is concerned about the lack of background commentary and contextual information associated with the release of annual statistics by the ATO covering the level of deductions under different categories of deductible expenditure. We consider the release of such data without accompanying explanatory material has allowed incorrect and misleading commentary about the regime. Further comments are contained in section 3 of this submission below.

Tax Rate/Deductibility Interaction

We consider the Paper to be incomplete as there is no reference to the appropriateness of the tax rate, particularly in the context of the canvassed changes. We note that in the tabling statement in 1991 into the operation of the PPRT legislation, the Minster for Resources noted that:

> *"The carry forward rates and the tax rate for the PRRT are part of a balanced and integrated package that includes wider deductibility for exploration expenditures. To preserve the community return, any adjustment in the carry forward rate for general expenditure would require a corresponding adjustment elsewhere."*

This statement highlights a balanced package of measures, where adjustments in key provisions necessitate a broader review of the impacts and the need for counterbalances elsewhere. We consider that the failure of the Paper to make any reference to the very high tax rate (40 per cent) that applies when a project incurs a PRRT liability in the context of possible modifications or restrictions to deductions or transferability reflects a significant gap in the review process.

Carry Forward Rates – Resource Super Profits Tax Revisited?

The Paper raises a number of issues which were used to support the introduction of the failed 2010 resource super profits tax (RSPT). In particular, various comments are made in the Paper on the concept of what represents an appropriate carry forward rate for undeducted costs. There is seemingly a case made to use the carry forward rate arguments that underpinned the case for the RSPT (where refunds were to be guaranteed for unprofitable projects) and then apply that logic as a possible basis for a change to the augmentation settings for the PRRT. We hold concerns about this logic.

The purpose of the carry forward rates is quite clear for the PRRT. It is intended to tax the economic rent associated with projects, with the economic rent being a direct reflection of project risk. Ross Garnaut and Anthony Clunies Ross in 1975 noted in a general discussion about resource rent taxes that the question of the threshold rates for petroleum and natural gas were particularly important, given the risky nature of aspects of the investment for these types of resources.

In its present form, the paper is seemingly adopting an RSPT view of the nature of the carry forward rates, while the risks that confront oil and gas investments in Australia are ignored or discounted. The Government's 1992 report into the operation of the operation of the PRRT noted that:

> *"The 15 per cent premium for exploration and five per cent rate for general expenditures was established to recognise the relative risk characteristics that the different stages of a petroleum project".*

APPEA agrees with the comment in the Paper that, in determining the correct uplift rates, it is important to consider their interactions with other parts of the regime. This was specifically done in implementing the 1990 amendments to the tax when wider deductibility was introduced (the carry forward rates were reviewed and subsequently modified). The fact that the Paper is silent on the interaction between the carry forward rates and the tax rate remains a significant gap in the review.

<u>Access to Starting Base Deductions – Onshore Projects</u>

The decision to extend the PRRT regime onshore and to the North West Shelf project presented the industry with the dual challenge of facing a new impost on petroleum investments and a further compliance burden. APPEA canvassed in detail the issue of the transitioning provisions for onshore projects in our submission to the Callaghan Review.

The starting base provisions were a critical design feature of the application of PRRT onshore, as PRRT was never originally intended (or designed) to apply to onshore operations. The Policy Transition Group (PTG) that considered the onshore application of PRRT recommended provisions that were logical, introduced integrity and acknowledged that the operating environment for onshore projects is fundamentally different to offshore projects. It was also considered important to respect and acknowledge past exploration and development decisions onshore. In addition to the starting base provisions, arrangements were also introduced to address the combination of projects (reflecting the highly interconnected nature of onshore operations) and the treatment of other resource tax payments.

Recommendation 2 of the Callaghan Report contains significant challenges for the onshore industry and will, if implemented in the form stated in the Paper, put at risk the future development of onshore petroleum resources in Australia. Based on the minimal commentary in the Paper, the recommendation would also be likely to significantly increase the complexity of the regime for companies with onshore interests.

The proposal, as understood by APPEA, would fundamentally change the onshore project combination provisions under the Act by denying licence holders the ability to combine some interests to form a single project (a denial never contemplated under the legislation), purely on the basis of the time of application and status of a permit. In all other respects, the operations will be undertaken as a combined or connected set of activities. Not only will this significantly restrict deductions for some project interests, it will lead to multiple projects purely for PRRT purposes within what in reality will be single projects.

It is important to note that the explanatory memorandum accompanying the 2012 extension of the PRRT specifically referenced the integrated nature of onshore operations.

> *"2.98 For example, coal seam gas and other unconventional gas projects may involve a large number of tenements and wells, and a broader geographic boundary than conventional petroleum projects. The ability to combine tenements which feed a common processing facility is accommodated by the new law."*
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> *"2.100 Although geology is an appropriate factor to consider in relation to offshore projects, if it were to apply to onshore projects it is likely that few, if any, projects would be able to be combined. This, in turn, would greatly increase complexity and compliance costs for both taxpayers and administrators."*

In addition, the PTG made the following recommendation in relation to starting base deductions:

> *"Recommendation 88: Starting base amounts should be treated in the same manner as general project expenditure, being immediately deductible, non-transferable and non-refundable, with undeducted amounts uplifted in accordance with the existing augmentation provisions. An exception would be the exploration expenditure component of a look-back starting base, which should be treated in accordance with the existing provisions relation to exploration expenditure."*

The following comment was also made:

> *"Of the projects to be transitioned to the PRRT several are liquefied natural gas projects, both existing and planned, in which investments have been made according to the existing tax regimes. Any significant change in tax regimes will potentially impact on the viability of these projects which have secured customers but are yet to reach final investment decision to proceed, or have in place long term fixed contractual arrangements."*

It is respectfully submitted that the change canvassed under Recommendation 2 will directly impact existing LNG and other integrated onshore projects, a concern that was clearly highlighted at the time by the PTG. If this recommendation is introduced, it is critical that an appropriate definition of what represents a new project accompany any change, recognising the integrated nature of onshore petroleum projects. Overall, APPEA and the onshore industry strongly oppose any change to the onshore project combination provisions. We consider Recommendation 2 to be both retrospective in nature and having potentially significant consequences for future energy supplies in Australia.

APPEA members are individually assessing the potential impact of any changes. It is expected that companies will address these concerns directly with both the review and state/territory jurisdictions that will be adversely impacted by any changes.

<u>Gas Transfer Price Methodology</u>

The introduction of the gas transfer price (GTP) methodology followed an extended period of consultations involving Treasury, the ATO, the industry department and APPEA. External expertise was also sourced.

The value of petroleum at the taxing point is one of the most important factors in determining a PRRT liability for a project and therefore the impact of PRRT on project economics. Significant project investments and long term contractual commitments have been made on the basis of the present methodology. It has provided investors with the necessary certainty to justify investments worth tens of billions of dollars.

Like other aspects of the PRRT, the GTP methodology balances a range of different factors. These were discussed in detail during the residual pricing methodology (RPM) consultation process. The RPM is based on the relatively simple principle of allowing a return to both the upstream and downstream portions of an integrated petroleum project. The residual amount (the return above a defined rate) is split equally between the upstream and downstream segments.

There is commentary and assertions in the Paper about aspects of the operation of the GTP that lack evidence and are selective. In addition, there appears to be an oversimplification of some aspects of the value chain for LNG operations.

The paper raises a series of questions, including whether a comparable uncontrolled price (or CUP) can be used more widely or whether an alternative methodology can be implemented. The RPM was introduced primarily because a CUP was generally deemed not to exist. We consider this still to be the case today. For example, in determining whether a CUP exists, a range of factors, including the following, would need to be taken into account:

- Contract terms including volumes, discounts, exchange exposures and all other relevant conditions that would reasonably be considered to affect the price.
- Marketing strategies and spot sales above or below marginal cost such as market penetration sales or maximisation of profit sales.
- Technology used to produce the liquefied product and processing cost.
- Any other comparability factors that it would be reasonable to consider.

As previously indicated, the RPM raises complex issues that require extremely careful judgement. We consider this can be best achieved through a separate process of engagement between the government and industry participants. Further detailed comments on aspects of the GTP methodology are outlined in Section 2 of this submission.

<u>Application of Changes</u>

APPEA has provided commentary below on what is a new project. This is an important issue, and must be viewed in the context of the physical operations of integrated projects and the whole life cycle of investments. It is important to note that investors must make commitments to undertake exploration at the time of an acquisition of an interest in an exploration permit – the fiscal framework in place is a determining factor that impacts on the initial permit commitment.

As advised above, we are also concerned about the complexities arising from poorly considered changes that could effectively produce a two tiered tax system.

2 Comments on Consultation Issues

Outlined below are comments in relation to the broad categories of issues raised in the Paper. We do not consider it practical to provide detailed commentary on individual consultation questions, as the PRRT provisions represent an integrated package of measures that cannot be viewed in isolation.

We also consider a number of options raised would fundamentally change the design of the PRRT from being a profits based tax to one more akin to a turnover based system.

2.1 Augmentation (Uplift) Rates

Consultation Questions

1. Of the options outlined above, which option, or combination is preferred? What are the advantages and disadvantages of each option? Which options could be considered in combination?
2. Given that transferability provisions have been inserted in the system, should exploration expenditure continue to attract a higher uplift rate (or larger investment allowance) relative to general expenditure?
3. If exploration expenditure continues to attract a higher uplift (or larger investment allowance) than general expenditure, what is the appropriate differential?
4. If the uplift rates are lowered, what would be the appropriate rates for exploration, and general expenditure?
5. Which option is likely to be the most robust to changes in the industry (for example, infrastructure sharing, future oil and gas discoveries)?
6. If deductions were to be uplifted for a set number of years, what would the appropriate time period be? When would be the most appropriate time to apply this limit from (for example, from the time expenditure is incurred or from the time a project obtains a production licence or starts producing)?
7. If an investment allowance was introduced, what would be the appropriate amount for the initial deduction? What would the appropriate uplift be thereafter?
8. What is the appropriate uplift rate for resource tax expenditure?

APPEA is concerned about the overly simplified discussion in the Paper that seeks to justify possible reforms to the present augmentation (carry forward) provisions. On the one hand, the Paper suggests the rates should be changed, however on the other, states that the move to a greater focus on gas developments has changed the period over which costs are recovered. On this latter point, we assume this implies longer periods are required to recover costs.

There is also the comment that the risk of recovering exploration costs is reduced with the introduction of transferability (presumably to other PRRT paying projects held by a taxpayer) – this may be the case, however many investors are unable to use this option. Most costs remain non-transferable. This includes many feasibility costs incurred before a final investment decision associated with a project. In the event that a project does not proceed and a permit is relinquished, these feasibility costs can effectively be lost to a taxpayer, an outcome that does not seem to have been contemplated in the original design of the tax.

Overall, the existing augmentation rates, when viewed as a package, appropriately reflect the levels of risk associated with the activities encountered in the different phases of petroleum exploration and production.

The higher carry forward rate that applies for some exploration costs reflects the significant risks associated with exploration. Conversely, the lower GDP factor rate for exploration can seriously disadvantage investors in circumstances where development decisions are delayed due to factors outside the control of an investor. The existing five year rule period, which may have been appropriate in the 1980s, can now be viewed as increasingly out of date due to the processes that must now be completed and the regulations that must be navigated before lodging a production licence application.

The use of augmentation rates remains the best approach to calculate the risk adjusted returns for individual petroleum projects. Any move towards capping or setting restrictions on the number of years for which deductions can be compounded would fundamentally compromise a key principle of the regime that seeks to allow an investor to achieve a risk adjusted return before the imposition of a tax liability. Similarly, any proposal that would seek to replace the carry forward provisions with an investment allowance would again compromise the operations of the carry forward provisions and disadvantage projects with long pay back periods. Even if this latter principle was accepted, the rate of 110 per cent is manifestly inadequate, particularly if combined with an artificially low carry forward rate.

The decision to introduce relatively limited (but nonetheless important) transferability for one category of expenditure was considered in detail in 1990. At that time, it was decided to significantly reduce the general project cost carry forward rate as a trade-off for wider deductibility of exploration costs. Exploration remains a high risk activity and the significant restrictions on the transferability of any other costs (including some other exploration expenditures incurred by a taxpayer) would suggest that there may indeed be a stronger case to increase the general project cost carry forward rate rather than reduce it.

Overall, the individual carry forward rates need to be viewed as a package of measures, together with the wider deductibility and ordering of deduction provisions. It is overly simplistic to consider what the differential between the rates should be in isolation of the broader package of provisions.

In terms of the operative augmentation rates, we do not believe compelling evidence has been provided in the Paper for any change. As discussed earlier in this submission, the justification seems based on the discussion that took place at the time of the proposed introduction of resource super profits tax (RSPT) in 2010. We do not consider that any comparison between PRRT and RSPT is appropriate. Again, we note that the Paper is largely silent on the question of the appropriateness of the very low GDP factor rate.

Resource Tax Payments

The treatment of other resource tax payments represented a key element of the package implemented at the time of the extension of PRRT onshore and to the North West Shelf project. Onshore petroleum projects are subject to royalties imposed by State and Territory governments, while Commonwealth production excise also technically applies to crude oil and condensate produced onshore (see comments below in Section 3). The North West Shelf project is subject to Commonwealth royalties and production excise, while a resource rent royalty is applied to petroleum production from the Barrow Island project.

Commonwealth, State and Territory resource tax expenditures are creditable in the assessment of a PRRT liability for an individual project. This ensures that petroleum projects are not subject to double taxation. Resource tax expenditure is deductible if it is incurred in relation to the petroleum project or any pre-combination petroleum project in the financial year and it relates to petroleum recovered after 1 July 2012. The PTG noted that:

"To reflect the fact that existing Government resource taxes will apply alongside the extended PRRT, the resource taxes that entities pay are to be credited against the PRRT liability of a project.

The recognition of Australian, State and Territory government resource taxes under the extended PRRT raises a number of important issues. Generally speaking, the current resource taxes are set at rates that industry can afford to pay, at least during normal times, and provide the governments with a relatively stable revenue stream. On the other hand, these existing regimes are less flexible during an industry downturn and can unnecessarily damage the industry and prevent optimal resource extraction. Further, by their nature, some existing resource taxation regimes do not capture the economic rents during a boom period.

Through the extension of the PRRT, Australia has the opportunity to substantially improve the overall outcome of resources taxation in this country. It provides a way to meet the needs of the States and Territories and captures more of the profits at the peak of the resources cycle, in a way royalties cannot, for the benefit of all Australians.

Recognising this objective as well as the importance of preserving Australia's international competitiveness, the PTG recommends that there be full crediting of all current and future resource taxes under the PRRT so as to provide certainty about the overall tax impost on the petroleum sector."

Policy Transition Group Report 2010 (p.93)

APPEA considers the current treatment (including compounding of undeducted amounts at the general project cost uplift rate) remains appropriate, as any diminution of the present arrangement would see PRRT effectively be applicable at a stage that conflicts with the other resource taxation payments made by a licence holder.

2.2 Ordering of Deductions

Consultation Questions
9. Is the proposed dual principle appropriate? 10. How material is the impact of changing the order of deductions as compared to other options (such as changing the uplift rate for exploration expenditure)?

As noted in the Paper, the ordering of deductions can in some cases materially impact on the timing and level of payments of PRRT. This arises through the existence of different augmentation rates and the operation of the compulsory transferability provisions. The ordering rules can positively or negatively impact on different projects, depending on the tax and activity profile of individual companies. Taxpayers in the same project can have materially different profiles. In addition, the timing provisions (particularly for the five year GDP factor rule) can also have a significant impact. It is important to remember that the incidence of the ordering rules are generally outside the control of individual taxpayers.

The provisions covering the ordering of deductions in the PRRT Act in part reflect the changes made to the regime since its commencement in 1987. In particular, the introduction of the wider deductibility rules in 1990 have had an impact on the breadth and timing of deductions, while the extension of PRRT onshore and to the North West Shelf project has had a lesser impact.

The Paper presents a modified approach for comment, with the proposed principles being expenditure with higher uplifts being deducted before expenditure with lower uplifts, and transferable expenditure before deducted before a projects own expenditure. APPEA would observe that there is clearly no single 'correct' approach. The proposal in the Paper would seem to have as a core objective a desire to limit the compounding impact of carrying forward deductions by deducting the lowest compounded rates last. This is primarily a tax revenue driven outcome – it is possible that other approaches could also be adopted based on different criteria. The Paper also points out that any changes to the augmentation rates would impact on the incidence (and therefore importance) of the ordering rules.

In addition, the Australian Accounting Standards Board guidance states that PRRT is an income tax for accounting disclosure purposes. However, there is an absence of formal guidance in the accounting standards in relation to recognising a deferred tax asset on the expected use of carry forward balances for PRRT projects. Individual oil and gas companies liaise with their external financial auditors to determine the most appropriate approach to comply with the accounting standards. Some companies, with guidance from their external financial auditors, analyse the PRRT tax effect accounting position in line with the ordering for the PRRT taxable profit calculation. This means that any change to the ordering of deductions will also need to consider the impact it may have on the accounting disclosures in relation to the tax effect of future deductible carry forward PRRT deductions.

While APPEA is of the view that a single standout approach that meets all circumstances does not exist, we do not support an approach that merely aims to arbitrarily reduce deductions. It is therefore recommended that further discussions take place on the operation of ordering of deductions as the review further advances, recognising that the final ordering can have a material impact on the profitability of individual investments.

2.3 Transferability

Consultation Questions

11. Is a consistent set of outcomes for PRRT taxpayers desirable or should the focus be on rewarding companies that have multiple projects underway?
12. Should transferability remain part of the PRRT or should the risk of never being able to offset some deductible expenditure against revenue be accounted for in some other way?
13. Treasury is interested in views on these options – the positives and negatives – and the reasons why one approach may be favoured above others. Are there other approaches that could be considered?

APPEA supports the retention of the wider deductibility provisions. The 1991 amendments to the PRRT introduced a significant and broadly accepted change in relation to the treatment of exploration costs. In August 1990, the Minister for Resources indicated that:

"The existing greenfields resource rent taxation arrangements will be amended to allow all exploration costs incurred by a company in areas where RRT applies, including Bass Strait, to be written off against company resource rent tax liability. This will widen exploration cost deductibility from a project to a company basis. Development costs will remain on a project basis.

Where no RRT liability exists, exploration costs will be able to be carried forward at a threshold rate of 15 percentage points above the long term bond rate. Currently, the threshold rate is about 28 per cent. Development costs will be eligible for carry forward at 5 percentage points above the long term bond rate. The lower threshold rate for development and production costs more clearly reflects the lower risk associated with development relative to exploration. Exploration and general project expenditures incurred more than 5 years before a production licence comes into force are compounded forward at the GDP factor until they can be written off.

***The new arrangements for exploration expenditure will make the immediate after-tax cost to a company of exploration within RRT liable permits the same as the cost outside those permits. Economic efficiency will therefore be improved by removing the current disincentive to explore in frontier areas.**" (Emphasis added)*

While this statement focused on the mechanics of the new provisions and the desire to remove an obvious distortion that encouraged companies to limit exploration to areas (or projects) where a PRRT liability already or would likely exist, the changes were also seen to have a wider energy policy context when they were referenced in the 1990-91 Federal Budget.

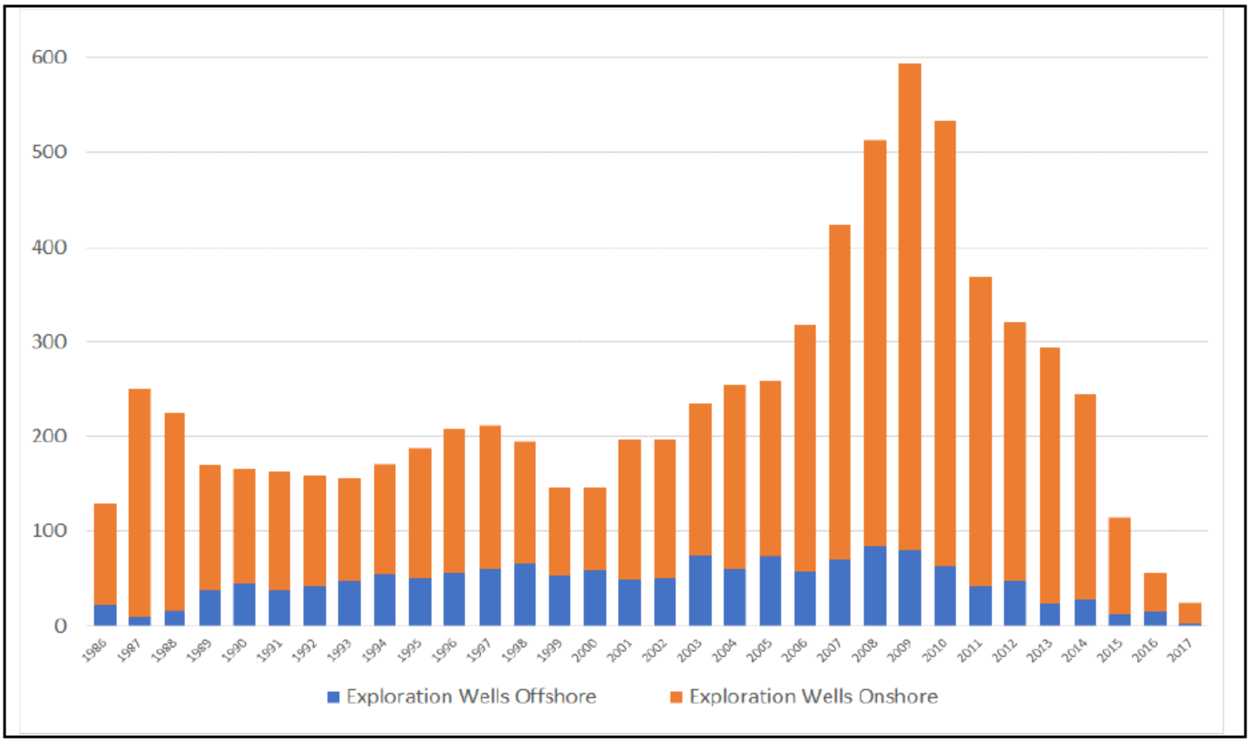
"The change to company wide deductibility of exploration costs will encourage the broadening of the exploration effort to frontier areas. There are largely unexplored basins where good prospects for major new oil finds exist. Previously, deductibility was limited to individual permit areas; as a result, for a company, after-tax exploration costs were lower in a RRT paying permit area than in prospective frontier areas. The change to a company wide system will equate a company's after-tax costs for exploration in all RRT offshore areas."

1990-91 Federal Budget, (p4.6)

It is generally acknowledged that Australia remains lightly explored for oil and gas, with significant hydrocarbon potential existing in under or unexplored areas. The wider deductibility provisions have played an important role in positively influencing exploration investment decisions in the industry. The provision has also signaled the Federal Government's long standing commitment to petroleum exploration in Australia.

Any change to the existing provisions would need to be mindful of the impact on future exploration, particularly at a time of historically low levels of activity. Chart 1 demonstrates the recent decline in exploration – any policy changes that exacerbate this decline or hinder any rebound in activity clearly need to be very carefully considered by the Government.

Chart 1: Petroleum Exploration Wells Drilled – Australia (1986 to 2017)



Source: APPEA/Pitney Bowes Australia

After Tax Values – Different Investors

Due to the operation of both the transferability and deduction provisions, the after tax cost of undertaking petroleum exploration in Australia will inevitably vary depending on the relative tax position of individual entities. This situation is not unique to PRRT – it applies equally for company tax purposes. APPEA does not see merit in any proposal that would seek to eliminate or modify the wider deductibility or transferability provisions simply on the basis that an entity is able to use a deduction, either within a project or in another project. Such an approach would have significant adverse consequences for the investment decisions of companies that have demonstrated a long term commitment to invest in Australia.

2.4 Gas Transfer Pricing

Consultation Questions

14. What approach to reforming the CUP rules in the Regulations are the most appropriate in terms of meeting the outcomes identified in the Review of fair distribution of rents, simplicity and transparency and ease of compliance?
15. What, if any, are appropriate combinations of gas market price indices on which to build a notional or proxy CUP?
16. What safeguards may need to be put in place to ensure that the CUP price does not exceed the proceeds of the LNG operation?

17. What safeguards may be needed to ensure that liquefaction operations are able to cover costs, and if so what is an appropriate way to recognise this amount?
18. What, if any, unintended consequences may arise from removing the asymmetric treatment of the upstream and downstream businesses?
19. What would be an appropriate allocation key within the context of the RPM, to appropriately attribute residual profits upstream and downstream so that they more appropriately reflect the respective economic rents of each operation?
20. Are there any other aspects of the RPM that result in asymmetric treatment of upstream capital? Are there any aspects of the RPM that result in asymmetric treatment of downstream capital?
21. Are there reasons that the capital allowance rate in the RPM should reflect the cost of equity rather than the lower weighted average cost of capital?
22. As the global LNG market grows and LNG facilities proliferate, what are the unique and valuable assets that are used in the downstream operation?
23. How are intellectual property and know-how generally rewarded in arm's length arrangements, for example third party tolling arrangements?
24. For PRRT purposes, should the design of a netback methodology result in downstream liquefaction facilities sharing in the upside of increases in the LNG price above that necessary to sustain investment and to what extent?
25. What transfer pricing methodology and what features of that methodology would ensure an appropriate distribution of any rents to the upstream and downstream business in a way that would truly reflect an arm's length agreement?
26. The taxing point were moved to the end of LNG production, what other adjustments should be considered to ensure an appropriate recognition of rents?
27. How should the PRRT account for rents in the liquefaction business to the extent they exist in any given project?
28. How would moving the taxing point for LNG impact on other petroleum products?

As indicated in Section 1 of this submission, the consultation period provided for such a complex issue is inadequate. APPEA notes that the present model was effectively developed over nearly eight years. Many of the issues are conceptually complex – the development of the GTP methodology required third party input to address a number of issues that are canvassed in the Paper. In 1998, expert consultants considered in detail the majority of the matters raised in the Paper in a report prepared for the then Department of Primary Industries and Energy (the 1998 Report). The 1998 Report remains the benchmark for integrated gas to liquids project ringfence pricing discussions in Australia.

The comments below discuss different aspects of the GTP methodology.

The Project Ringfence Point

Any change or extension of the project ringfence to include liquefaction processes, the storage of LNG, transport (including shipping) and marketing activities would fundamentally compromise the objective and operation of the tax, which seeks to tax the economic rent of the underlying resource. It is not intended to be a tax on value adding activities (other than on the recovery of the underlying resource). Any extension would in effect apply a second layer of company tax on the value adding activities of such operations. APPEA considers the existing taxing point remains appropriate.

Investment Certainty - RPM is the Superior Model

The valuation of product within an integrated gas to liquids project is one of the most important parameters that influences investments in these types of projects in Australia. It has provided investors with the certainty necessary to justify large scale long term investments.

The 1998 Report commissioned by the Department of Primary Industries and Energy assisted in both confirming the appropriateness of the RPM and defining a number of the key settings.

> *"Investments in integrated gas to liquids projects require significant capital investments. The returns are typically low but they do provide a fairly certain flow of gas and cash flows through long term contracts. The decision to proceed with a development is often based on securing a contract and a certain after tax return over an extended time period.*
>
> *A transfer pricing methodology or review period which reduces the certainty of those returns has the potential to cause investors to delay developments which would otherwise go ahead. This misallocation of resources reduces the economic efficiency of the development and the benefits to the community as a whole.*
>
> *Certainty is best served by having a gas transfer pricing calculation which does not change over time and a structure which does not vary. The methodology outlined in this report, if implemented, should be maintained over the life of the project."*

1998 Report (p.34)

The RPM was considered by the independent consultant to provide investors with the necessary certainty to justify long term investments as well as the need for it to be maintained over the life of a project where it applies.

The 'Residual Pricing Methodology' – The Adopted Model

The final approach adopted (the residual pricing methodology) was accepted by government, industry and the consultant as the clearly superior model for determining a price for gas at the point of a marketable petroleum commodity. The principle was communicated to APPEA in 1999 by the industry department:

> *The RPM, which is to be used to determine the GTP, will utilise:*
>
> - *A netback approach to determine the maximum price a downstream producer (liquefier) is willing to pay for feedstock natural gas to earn the minimum return necessary to continue production; and*
> - *A cost plus approach to determine the minimum price and upstream (natural gas0 producer is willing to accept for natural gas product to earn the minimum return necessary to continue production.*
>
> *When the netback price is higher than the cost plus the difference will be apportioned on an equal basis between the upstream and downstream phases of the project, recognising the integrated nature of the project. When the cost plus price is higher than the netback price the value of the MPC will be equal to the netback outcome."*

Department of Industry, Science and Resources note to APPEA (25 May 1999)

Understanding the Profit Split

A key element of the RPM is the allocation of 'profit' between the upstream and downstream phases of a project. The final approach adopted reflected the integrated nature of gas to liquids projects, with an equal apportionment of any residual amount between the upstream and downstream phases. Arthur Anderson made the observation below about the apportionment of any residual rent when preparing their report in 1998.

> *'Unfortunately, there is little if any guide as to the way in which independent parties (upstream or downstream) would split the residual profit (or price) in an arm's length sale of feedstock gas into an integrated gas to liquids project.*
>
> ++++++
>
> *In light of this situation any method is essentially arbitrary. In this regard it was considered that the most appropriate and potentially equitable solution is to split the residual price 50:50 between the upstream and downstream operations. The gas is worth little without a mechanism to get it to a market (ie through liquefaction) and the processing is worth little without access to a large and sustainable supply of cost effective gas"*

1998 Report (pp.22, 23)

The industry department confirmed this position in 1999, noting that the 50/50 split represented the most equitable treatment.

> *"The difference between the natural gas price generated by the application of the netback price compared to the cost plus price identifies the residual profit for a project ('the residual profit element'). Factors contributing to the residual profit include resource scarcity, intellectual property and know how related to gas production, processing and marketing.*
>
> *Although the application of the netback and cost plus approaches define the residual profit in a project no theoretical basis exists for determining how the residual profit should be split between the various different elements noted above.* ***The Government's decision to split the residual profit 50:50 between the upstream and downstream components provides the most equitable solution."*** (emphasis added)

Department of Industry, Science and Resources note to APPEA (25 May 1999)

APPEA is unaware of any material change between 1998 and 2017 that would alter this position, nor are we aware of any further work that has been undertaken on behalf of the Federal Government to change this position.

By way of example, APPEA considers that events regarding the development of the coal seam gas to LNG industry on the east coast of Australia support a 50/50 split of project profit as appropriate for even the most recent LNG project developments. The circumstances around development of the CSG industry were that the entities which discovered and initially developed the CSG reserves were unable to bring those reserves to market without the assistance of companies with an established LNG liquefaction and marketing capability.

The difficulty faced by the upstream producers is that there was no domestic market for the large volume of gas identified, and it was not until international partners arrived with downstream liquefaction expertise and the reputation required to engage in LNG marketing that those CSG reserves became marketable as exported LNG. It is a reasonable conclusion that the upstream and downstream parties each needed the skills and resources of the other to bring the reserves to market, and this symbiotic relationship would be reflected in an equal sharing of the risks and rewards of the joint venture as a whole.

Capital Return – Upstream/Downstream

The 1998 report examined the issue of the appropriate return for the upstream and downstream phases in terms of the cost plus and netback calculations. It was recommended that the same rate be used for the different phases of an integrated project.

> *"The rate of return which best estimates the 'appropriate' profit or 'normal' economic return of upstream LNG processes is the WACC. As discussed in the appendix of this report the same WACC rate is used for both netback and cost plus calculations, thus obtaining a WACC for the integrated project is appropriate in this case"*
>
> *1998 Report (p.18)*

Existence of a Comparable Uncontrolled Price

The Paper raises the question about the existence of a comparable uncontrolled price (CUP) and whether such a price should be used as a replacement to the RPM. Under the present law, in the event of the existence of a CUP, it would generally take precedence over the RPM. Notwithstanding this, the 1998 Report considered in detail the question of a shadow price, noting the conditions that would need to be met would make such a situation highly unlikely. It was stated that:

> *"Before a shadow price can be used, a comparable arm's length price needs to be observable. This matter is discussed further below. In the event that either arm's length domestic or feedstock gas prices are observable, they would need to satisfy a number of criteria before they could be considered reliable comparables. The criteria for assessment would include*
>
> - *A determination of whether the prices which were observed were truly arm's length; and*
> - *An assessment of whether the prices were for the same or similar product transacted in the same or similar circumstances*
>
> +++++++++
>
> *Comparability of shadow prices*
>
> *While all comparability factors need to be taken into account there are a number of key which will drive price variations in the domestic gas and feedstock gas markets. They include:*

- *product similarity (this would probably be achieved by considering sales gas, that is 50% methane, however if the domestic gas to which the shadow price relates would require further processing these costs would need to be accounted for);*
- *market similarities (the elasticity of demand for gas in the domestic market is likely to be different from demand in the feedstock gas market);*
- *contract terms (including volumes, discounts, and exchange exposures would need to be accounted for, this would be a substantial issue in comparing domestic gas to feedstock gas as the volumes are significantly different);*
- *strategies of buyers and sellers (if a gas producer is trying to penetrate a market or marginal cost gas and the prices of this gas are used as the shadow price, such factors would need to be accounted for)."*

1998 Report (p.26-28)

The supply of gas into integrated gas to liquids projects in Australia is characterised by a range of factors that make the existence of a 'common price' or CUP at the ringfence point highly improbable. Factors such as different gas qualities, different associated produced hydrocarbons, fundamentally different market conditions (gas processing versus gas for electricity generation versus gas for residential purposes) and substantially disparate reservoir and geographic localities mean the existence of a common price is largely an academic.

While the RPM is designed around arm's length principles, the use of some undefined proxy price would be both unlikely to meet the conditions/criteria outlined above and would generally be arbitrary in nature. In effect, the RPM approach calculates the CUP for the sales gas for each project. The fact that the Paper suggests that consideration could be given to applying compensatory adjustments for over-taxed taxpayers demonstrates the practical limitations of adopting such an approach.

Allocation of Costs

The consultation questions raise the concept of the asymmetric treatment of capital costs. APPEA is unaware of the existence of any such treatments. However we note that the 1998 report touched on the question of the inclusion of different categories of costs in the determination of the gas transfer price.

"In the context of current technologies it may be necessary to define cost centres and allocate costs for each project as follows:

- *Upstream, including development (eg drilling and storage, which are not exploration): transmission (relating to transporting gas from the PRRT ringfence to the processing facility); and*
- *Downstream, including processing (relating to the processing of gas to liquids); storage (relating to the storage of liquids prior to transport); and shipping (relating to transporting liquids to markets)."*

1998 Report (p.9)

"It is worth noting that final abandonment costs have not been included in the netback method (nor are they included in the costs plus method to follow). This is for two reasons. Firstly, those abandonment costs that occur prior to the project being completed will be

picked up as operating expenditure during the life of the project, and secondly the final costs would have no impact on the gas transfer price since no gas is being produced. These do not represent 'black hole' expenditures since they would be picked up in the PRRT and company tax calculations'."

1998 Report (p.16)

APPEA considers the residual pricing methodology provides the most practical, accurate and robust approach for determining the value of petroleum at the project ringfence point. It has provided investors with the certainty required for commitment to large scale project investments.

Any further review of the methodology should be undertaken as part of a separate process, with the Government seeking input from third party experts before making any further judgements about the accuracy or otherwise of the present model. It is also recommended that the ATO's role in administering the regime be publically restated to provide reassurance to the community about the integrity of the RPM.

2.5 What is a new project?

Questions for consultation

29. Are there any unintended consequences from having the new regime apply only to projects that have their production licence come into force after any amendments to the PRRT regime commence?
30. Should there be a delay between when the new changes are announced and when the new regime comes into effect?
31. Interested parties are encouraged to make comments on how the integrity of the new regime should be maintained where the opportunity exists for combinations to occur between projects within the new and existing regime.
32. Interested parties are encouraged to make comments on how the integrity of the new regime should be maintained where the opportunity exists for transfers to occur between projects within the new and existing regime.

The definition of what represents a new project is a key issue in the context of the review. It will impact on future PRRT liabilities from all projects and the viability of new petroleum project investments in Australia, including extensions and new capital injections to existing projects.

In a broad context, the petroleum investment cycle involves a sequence of integrated activities commencing with acquiring an exploration interest. If successful, exploration leads to project development, production and eventually the closure of a project. No single part of this process can be undertaken without the other parts. As such, a petroleum project is a broader concept than exists in the PRRT Act, which is effectively defined around a production licence.

In the case of some exploration permits and retention leases across Australia, many hundreds of millions of dollars have already been invested with final investment decisions still pending. The application of new tax settings to these sunk investments and to future commitments for allocated permits would represent a major retrospective changing of the rules. APPEA can see no compelling arguments to undermine the significant investments made by companies on the basis of a tax regime that has been in place for three decades.

In the event that changes are introduced to the operation of the regime, APPEA recommends that the test that should apply to define what represents a current project should be as follows:

- All production licences applied for and/or granted before the operation of any new provisions, plus
- All future production licences, where such licences are eligible to be combined with a production licence or PRRT combination certificate issued or applied for prior to the operation of any new provisions, based on the combination certificate rules in place as at 30 June 2017.

All existing exploration permits and retention leases where spending has been undertaken or is committed under work programs should also be regarded as current projects.

The continued use of the combination certificate rules is essential in recognising the integrated nature of many projects. This is particularly the case onshore where there this a clear and accepted need to incorporate new production licences into a combined project to generate the critical mass to commercialise production. This was specifically recognised in the 2012 extension of the regime onshore, where a downstream connectedness test was introduced into the combination certificate provisions.

APPEA considers it vital that the regime continues to operate in an integrated manner, including the continued wider deductibility of exploration costs between eligible projects. New arrangements were seamlessly implemented in 1990 when the revised provisions were implemented at that time. We would anticipate that any changes made as part of the present review would not need to be treated in a different manner.

The suggestion that the legislation could dictate an enforced coverage by any new provisions for the entirety of a project where one licence comes into existence in a combined project after the introduction of amendments to the regime proposes a level of sovereign risk and retrospectivity that is both inequitable and unacceptable.

APPEA also believes that this consultation process provides an opportunity to constructively address elements in the PRRT and other fiscal settings that should be explored to incentivise the development of stranded resources in less capital intensive ways, including by addressing the asset merger rules. Issues such as the competitiveness of Australia's company tax depreciation settings and encouragement for the adoption of new lower emission technology by projects under the PRRT also warrant attention.

2.6 Changes Recommended by the Review to Improve the Integrity, Efficiency and Administration of the PRRT

Questions for consultation

33. Are there any unforeseen consequences of implementing recommendations 2 through 12 (excluding recommendation 3) of the Review?
34. For recommendations that affect the ATO's administrative powers, are there any specific safeguards that should apply to the exercise of powers by the Commissioner of Taxation?
35. How significant are the compliance cost savings and/or transitioning compliance costs/burden associated with these recommendations?

The comments below are based on APPEA's understanding of the proposals outlined in both the Paper and the Callaghan Report. Limited information has been provided upon which to provide detail commentary, and we note that the impact of any measures will be dependent on the final form of any amending legislation.

Prohibit new onshore projects from combining with onshore projects that have a starting base *(Recommendation 2 of the Callaghan Review)*

See comments above. APPEA believes the proposal to restrict access to starting base deductions represents a retrospective change to the operation of the regime, it undermines the intent of the operation of the provisions for onshore projects and will seriously impact on the ability of investors to commercialise onshore resources.

The potentially negative consequences of such a change could be considerably wider depending on the approach used to implement such a change. For example, the provisions whereby deductions attach to the first production licence drawn from an exploration permit or retention lease could see some future production licences denied an ability to obtain any historical deductions (whether they be starting base or exploration in nature) by denying a second and subsequent licences with the option of being combined with the first licence issued from the same exploration permit or retention lease.

Recognition of partial closing down expenditure as a legitimate general project expense *(Recommendation 4)*

APPEA sees merit in this recommendation as it aligns the operation of the PRRT Act with operational practice, where facilities associated within integrated petroleum operations can be closed down on a progressive basis. We see this change as reflecting the broad intent of the legislation.

PRRT taxpayers to lodge annual returns after they start holding an interest in an exploration permit, retention lease or production lease *(Recommendation 5)*

We note that this recommendation is focused towards addressing the perceived lack of visibility on the quantum of future potential deductions under the PRRT system. The introduction of a mandatory system of lodgement (irrespective of whether a company will or will not ever produce petroleum from a permit or licence) will require all licence holders (irrespective of the size of a company) to lodge a return. This will, by definition, impose an additional administrative burden on all licence holders. The impact of this measure will be dependent on the compliance obligations and processes imposed by the ATO.

If such an obligation is introduced, it must be accompanied by a provision similar to the one that applied with the introduction of the starting base deductions under the extended PRRT regime, whereby the ATO has a statutory period to dispute deductions. The introduction of such a provision would provide benefits to both the ATO in terms of obtaining more information about potential deductions, as well as taxpayers, who would be provided with increased certainty about future deductions under the regime. It would also assist in providing more certainty where transfers of interests take place in permits and licences.

Provide the Commissioner of Taxation with power to treat a new project as a continuation of an earlier project (*Recommendation 6*)

This recommendation seeks to address an anomalous outcome whereby a licence holder loses an entitlement to certain deductions when a production licence reverts to a retention lease. It is APPEA's understanding that this outcome was not envisaged in the drafting of the original legislation. While not impacting on a large number of licences or taxpayers, it will ensure that unintended outcomes are minimised.

Provide the Commissioner of Taxation with the discretion to recognise more than one project from a production licence area where there are genuinely separate and independent petroleum operations in the licence area (*Recommendation 7)*

As the industry's operations have become more technically and commercially complex, the definition of what represents a project in the PRRT Act has not kept pace in situations (particularly onshore) where more than one project or joint venture can exist within a single exploration permit or production licence area. For example, different joint ventures or interests can exist at different stratigraphic levels within a single or combined licence area. Under the PRRT Act, limitations exist in relation to allocating deductible expenditure to the different ventures.

APPEA understands that the intention of the change is to allow the ATO to recognise the existence of more than one project in a licence area, and for the legislation to ensure that deductible expenditure and receipts are correctly allocated to the different projects. Such a change is supported.

Extend to offshore projects the option of having all interests held within a group to be reported as a single PRRT return (*Recommendation 8*)

APPEA understands this is an administrative change that will allow taxpayers with multiple interests within a group to lodge a single return for offshore projects (a similar provision already exists onshore). APPEA is not aware of the number of taxpayers impacted, however it has the potential to provide some minor compliance savings for impacted parties.

Provide taxpayers the ability to adopt a substituted accounting period (*Recommendation 9*)

APPEA understands that this is purely a technical amendment that, if implemented, has the potential to provide impacted taxpayers with modest compliance cost savings.

Provide choice of functional currency to taxpayers operating with a Multiple Entry Consolidated (MEC) group (*Recommendation 10*)

Similar to recommendation 9, this is primarily a compliance/technical change that will provide taxpayers with compliance savings without impacting on the integrity of the PRRT.

Provide the Commissioner the ability to administratively exempt projects from PRRT obligations (*Recommendation 11*)

While this provision is generally supported, APPEA seeks clarification on the criteria that would define eligibility. Clarification is also sought as to the implications for the deductible expenditure where the exemption applies. For example, would a taxpayer lose an entitlement to use future deductions from the exempted project?

Make PRRT anti-avoidance rules consistent with those applying to income tax (*Recommendation 12*)

Such a change is generally supported to promote consistency across both forms of taxation. If adjustments are made under anti-avoidance rules under the PRRT, corresponding adjustments should also be applied to entities for income tax purposes.

3 Other Possible Enhancements

APPEA recommends consideration be given to the following enhancements/improvements to both the operation and publication of explanatory material about the operation of the PRRT.

General Operation of the Regime

Comments were provided in section 1 of this submission about the general lack of understanding of PRRT and incorrect statements by third parties about key provisions. While some information is available from the ATO website about the operation of PRRT, it is recommended that consideration be given to the preparation of more and clearer information to assist the community better understand the key operational features of the tax, the integrity measures that are in place and factors that need to be considered as to when tax is paid. In terms of this latter point, the debate would be assisted if it was made clear that onshore projects and the North West Shelf project are subject to additional taxes that effectively apply before PRRT.

APPEA would be pleased to work with the ATO and Treasury in the preparation of such information.

Arm's length requirements

It is recommended that consideration be given to address the issue of one sided adjustments in sections 57, 58 of PRRT Act (i.e. under the current rules, the Commissioner can adjust revenue up and deductions down, but not adjust in both directions). To promote consistency across different forms of taxation, if adjustments are made under arm's length requirements in PRRT, corresponding adjustments should also be applied to entities for income tax purposes where relevant.

Lodgment of PRRT returns

It is recommended that the lodgement period for annual PRRT returns be extended from 60 to 90 days to allow taxpayers to gather increasingly disparate and granulated information. The increasing complexity of the industry's operations has presented challenges for taxpayers in meeting the 60 day timeline. In addition, in the event that Recommendation 5 of the review is implemented (requiring the lodgement of pre-production returns), further consideration may need to be given about the general issue of lodgement periods.

Other PRRT Administrative issues

Other PRRT administrative and compliance issues that warrant consideration include the recognition of joint venture operator statements as evidence of expenditure incurred by a project operator, the extension of appealable decisions to include matters such as the ATO's denial to enter into negotiations with a taxpayer for an advance pricing agreement and an extension to deadline for the application of project combinations.

Federal Production Excise

Federal crude oil and condensate production excise is unlikely to be payable from onshore and state waters production in Australia. In the event that a liability is incurred, it has the potential to lead to the premature closure of producing projects due to the high rates of tax. In addition, taxpayers are required to maintain records and seek interpretations about what constitutes a relevant field.

With the new mandatory requirements being developed by the Federal Government for the reporting of crude oil and condensate production and stocks in Australia, the excise obligation merely impose an unnecessary additional compliance burden. APPEA recommends that the production excise provisions applying to onshore and state waters production therefore be abolished.

We look forward to discussing the issues raised in this submission further with the review team. Contact in APPEA is Noel Mullen (nmullen@appea.com.au).

Yours sincerely

M. Roberts

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