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Review of the PRRT Gas Transfer Price

Please find attached a submission from the Australian Petroleum Production & Exploration Association in relation to the review of the PRRT gas transfer price.

Contact in APPEA is Noel Mullen, [redacted]

Yours sincerely

Andrew McConville
Chief Executive

Submission to the Review of the PRRT Gas Transfer Pricing Arrangements

AUSTRALIAN PETROLEUM PRODUCTION & EXPLORATION ASSOCIATION (APPEA) LTD

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The Australian Petroleum Production & Exploration Association (APPEA) is the peak national body representing companies engaged in oil and gas exploration and production operations in Australia. APPEA's members account for the vast majority of Australia's oil and gas production and petroleum exploration.

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Consultation paper: April 2019

Objectives

1. On 2 November 2018, the Government announced its final response to the Callaghan Review of the Petroleum Resource Rent Tax (PRRT). As part of its response, the Government asked Treasury to lead a review of the gas transfer pricing (GTP) arrangements of the PRRT, to consult and report back within 12 to 18 months.

2. Treasury has been asked to provide advice to Government on:
   - options to reflect an appropriate distribution of rents, including when resource prices are high
   - ensuring the regulations are fit for purpose into the future and compatible with emerging developments in the industry, such as liquefied natural gas (LNG) tolling arrangements and third party processing
   - whether the evidence of how the regulations are applied in practice reflects an appropriate arm's length price for gas at the taxing point, including in situations where prices and resource rents are high
   - ensuring commercial transactions for parts of the LNG production chain are used as far as possible as a reference for establishing a gas transfer price
   - ensuring that the regulations are neutral as far as possible between operations where the owners (or part owners) of gas process their own gas and where gas is processed by third parties
   - options to improve transparency and reduce complexity in the way in which the rules operate, and
   - any other related matters.

3. The GTP review will have regard to the need to ensure the community receives a fair return for its oil and gas resources, while not discouraging investment in the industry.

Executive Summary

> *"Australian upstream and downstream fiscal systems are well established and understood, and provide a stable basis for significant levels of investment. Any structural change in approach to integrated LNG taxation which negatively impacts project economics or increases administrative burden, could derail the progress to final investment decision of a number of new LNG projects in Australia.*
>
> *This is because despite Australia's favourable resource and infrastructure position in global terms, no Australian LNG projects have been sanctioned since 2013. Projects in the USA, Canada, Russia, West Africa, Mozambique, Malaysia and Indonesia have all moved into development in the same period."*
>
> Wood Mackenzie Report to APPEA, 2019

The Australian LNG industry is still in its relative infancy, with a number of new projects only having recently commenced production. While new opportunities remain, Australia's success in attracting the necessary investment capital to underpin their development will be dependent on a range of factors, including the future operation of the petroleum resource rent tax (PRRT).

The review in the operation of Australia's petroleum resource taxation arrangements undertaken by Michael Callaghan AM PSM in 2017 represented the most comprehensive examination since the introduction of PRRT in the mid 1980's. The Callaghan report confirmed the important role played by a stable and profits based resource taxation regime in underpinning investment in Australia's offshore gas industry.

PRRT payments made by the industry are expected to significantly rise over the medium term as projects enter maturity and deductions are offset against income. The high level of deductions reflect the hundreds of billions of dollars of funds spent by taxpayers over the last decade. PRRT is designed in a manner such that PRRT is payable when a project's costs have been fully recovered. The relatively high PRRT tax rate (40 per cent) requires a regime that is genuinely profits based. Combined with company tax, a tax rate of 58 per cent can apply when projects become profitable.

The Government's consideration of the issues and recommendations contained in the Callaghan report led to a series of amendments to the scope and carry forward provisions of PRRT from 1 July 2019. In addition to a series of further technical amendments that are expected to be developed during 2019, a Treasury led examination of the gas transfer price regime represents the next key element of the review process.

The gas transfer price has been a key element of the PRRT regime since the mid 2000's. Its introduction followed concerns raised by industry about how certain aspects of the PRRT would apply to integrated gas to liquids projects. The development of the final model followed extensive consultations by an independent consultant (Arthur Andersen) about the provisions that were best suited for Australian liquefied natural gas projects. The final provisions implemented in 2005 have underpinned the massive growth of Australia's offshore gas industry by providing investors with a framework that has reduced a key element of volatility for large scale gas investments.

The Treasury review (supported by the released Consultation paper) has raised a number of matters concerning the operation of the gas transfer price, with a view to ensuring it remains fit for purpose. The issues raised by Treasury broadly fall into three categories:

1. The existence and potential application of comparable prices
2. The operation of the residual price methodology
3. Other related matters connected to the gas transfer price regime.

APPEA's submission addresses these three areas. The key conclusions are as follows:

Existence of Comparable Prices

Assessment against the relevant transfer pricing principles and arms-length guidelines clearly indicates the conditions necessary to establish comparable prices for feedstock gas do not exist. This conclusion is supported by advice provided to APPEA by Deloitte (see Attachment 1).

The Treasury Consultation paper seeks comments on how the comparative uncontrolled price provisions can be modified to make their application for feedstock gas an option for PRRT purposes. Modifications of the type either contemplated or required would significantly compromise the underlying principles that define the existence of comparable prices and render such an approach impractical.

"*Changing the valuation method for sales gas away from the RPM to a different method, either using arm's length or market valuation principles, may present greater challenges in terms of transparency, equality, auditability and simplicity.*"

Callaghan Report, p.93

Operation of the Residual Price Methodology

The residual price methodology (RPM) is an integral element of the gas transfer price regime. Key metrics include the operation of the residual profit split, the scope of excluded costs, the cost plus/netback interaction and capital allowances. Each of these components were considered during the design and subsequent consultations prior to the introduction of the final model in 2005.

APPEA considers that the existing provisions remain relevant and appropriate for the industry as it heads towards 2020. In part, this reflects the comprehensive nature of both the Arthur Andersen review and the consultation processes headed jointly by the Australian Taxation Office (ATO) and the Department of Industry, Science and Resources, as well as the overall design of the RPM that anticipated possible changes to the nature of the industry's operations.

The residual profit split of 50/50 remains the most equitable and balanced approach to the sharing of residual profits (assuming such profits exist). The split reflects the integrated nature of many LNG projects and the fact that risks are inherent in both the upstream and downstream phases of such projects. Changes to the present arrangement would represent a significant modification to an important element of an integrated package of measures. Advice provided by Wood Mackenzie supports the basis for a continuation of the existing split.

Costs that are presently excluded from the RPM (specifically exploration and closing down expenditures) should remain excluded both for in-principle and definitional reasons, while APPEA can see no case for change to the cost plus/netback interaction treatment and the capital allowance provisions.

Other Matters

Changes to the GTP regulations must be carefully considered and if implemented, should apply on a prospective basis and should not impose a significant barrier for project combinations. That is, the amendments should only apply to new projects which apply for a production licence from a date after the conclusion of the review. This principle of prospectivity is consistent with the Callaghan Report recommendations. Any changes resulting from the GTP review must be seen as separate from those already announced.

Detailed commentary in this submission is provided in relation to applicability of the present RPM provisions to toll processing arrangements. The efficient use of infrastructure can be achieved through extending project lives and processing third or related party gas. This provides significant and tangible benefits to investors and the community. The existing rules are generally workable for tolling related activities, however some aspects of their application in instances where common owners exist may need to be further considered.

Any changes made to shift the taxing point beyond where it presently exists would represent a fundamental shift in policy, altering the nature of the PRRT and represent a tax on all value adding activities. Such an outcome would be inconsistent with the overall thrust of PRRT which is to tax super profits associated with the petroleum resource.

Suggestions that the present sharing of rents should be adjusted depending on the price of LNG fail to understand the fully integrated and risk sharing nature of integrated projects. In any event, the upstream portion of projects obtain 50 per cent of any increase in prices under the existing regime.

A key to building community trust concerning the integrity and compliance with the PRRT regime is dependent on ensuring the regulator (the ATO) is both well-resourced and has the authority to satisfy itself that taxpayers are meeting their compliance obligations. This is presently the case.

Taxpayers also understand the need to undertake their operations in a transparent manner. Tax data is released annually by the ATO while many taxpayers with operations in the industry are now signatories to the voluntary tax disclosure code. Experience indicates that the release of information without detailed explanatory notes or that is out of context will lead to less, not more confidence.

Overall, APPEA considers that the unique design of the PRRT gas transfer price regime is both innovative and remains fit for purpose at a time when the industry is making decisions associated with the next wave of gas investment in Australia. APPEA has yet to see evidence that would support any case for significant change, noting the present provisions have underpinned Australia becoming a world leader in natural gas production.

Section 1: Background and Previous Reviews

> *"The petroleum industry faces considerable uncertainty in project planning and execution. Possible changes to oil prices, exchange rates, costs of production and production volumes are among the many risks that need to be addressed. Also influencing investment decisions is Australia's high cost structure. Given such influences, stable fiscal settings are important for companies planning long-term petroleum investments. The overall stability of the PRRT has contributed to the very large investment in the Australian petroleum industry."*
>
> Callaghan Report, p.10

The Federal Government completed a comprehensive review into the operation of the petroleum resource rent tax (PRRT) in late 2018. As an outcome of that process, it was announced Treasury would be tasked with examining the PRRT gas transfer price provisions with a view to ensuring they remain fit for purpose in the context of a modern and expanding gas industry in Australia. This submission addresses a range of issues identified in the Treasury Gas Transfer Pricing Arrangements Consultation Paper.

Overall, APPEA considers the existing PRRT gas transfer pricing provisions remain best practice for the industry in Australia. While we support the review of the present framework, little (if any) evidence has been raised in recent reviews of the PRRT suggesting significant change is either justified or required.

The comprehensive independent review undertaken during the late 1990's and the associated conclusions that underpinned the initial design and subsequent implementation of the gas transfer pricing regime remains as relevant today as it was two decades ago.

1.1 Development of the Gas Transfer Price Regime

Assessable receipts for PRRT purposes are determined with reference to a marketable petroleum commodity, or an MPC. At the time PRRT was introduced, the primary MPC's sold as part of petroleum operations in Australia where crude oil, condensate, liquid petroleum gas and a range of gaseous products for which the assessable receipts are generally determined at the point of sale. Following that time, the nature of the industry's operations have both expanded and gradually changed. This led to a series of enhancements to the operation of the tax to ensure it remained fit for purpose.

Following the release by the Federal Government of a Green Paper titled "*Sustainable Energy Policy for Australia*" in the late 1990's, APPEA identified the need for a number of changes to the PRRT settings to secure the nation's long term oil and gas supply capability. Specifically, APPEA noted that:

- The remoteness from infrastructure and markets often can make the economics of large scale offshore gas projects marginal.
- Large gas projects have the potential to generate significant benefits to the Australian and regional economies.
- Certain aspects of the operation of PRRT had the potential to impede future investment in gas projects.
- LNG market opportunities are scarce and global competition is intense.

APPEA highlighted to the Government in 1997 that "…*PRRT was not intended to apply to downstream activities like the liquefaction process. In commenting on this issue, the 1992 Report on Operation of PRRT is clear that 'The PRRT is a resource tax and should not extend to secondary activities where the community has no proprietary interest.' However, while it also notes that 'Where an MPC is produced in a plant, the Act has provisions permitting the determination of a market value at the point of production", how this would apply in practice to an LNG project is at best unclear.*"

Discussions took place during 1998 between government agencies and industry with a view to identifying options to address the question of potential pricing mechanisms for integrated gas projects in Australia for PRRT purposes. As part of the process, the Government engaged independent consultants Arthur Andersen to undertake a comprehensive review of a range of aspects of gas pricing, with the primary objective being to assess models that could be incorporated into the architecture of the PRRT.

As part of their final report to the Government, Arthur Anderson noted the following in the context of the practical application of any approach:

> *"Because transfer pricing is not a precise science practitioners should focus on material not esoteric methodological issues. Common sense and project economics at the end of the day should be key influences on the outcome of a transfer pricing analysis.*
>
> *Flexibility in the adaptation of a transfer pricing methodology but applied in a structured and consistent manner will provide taxpayers, industry, the government and the community in general with robust outcomes and greater certainty in respect to the determination of gas transfer prices and the calculation and collection of secondary taxes on resource extraction."*
>
> Arthur Anderson Report, p.7

The Government announced the outcome of its deliberations on 23 December 1998, in a joint media release issued by the Treasurer and Minister for Industry, Science and Resources. The Government indicated it would remove the uncertainty by incorporating a gas price formula within the PRRT legislation. It was noted that the final methodology (the RPM) had been developed in recognition of the vertically integrated nature of many gas projects in Australia – the model was also seen as being adaptable to other new types of gas to liquids projects.

Following the 1998 announcement, Treasury, the ATO and the Department of Industry, Science and Resources commenced work on developing the final details of the RPM. This process included targeted consultations with industry to ensure that the provisions reflected anticipated project structures, as well as accommodating commercial practice.

A discussion paper was provided to APPEA in late 2000 for comment by the ATO. In addition to providing details of the proposed mechanics of the RPM (including the treatment of different categories of cost), the paper contained advice on the factors the Government considered relevant in determining whether dealings are arms-length in nature and if a comparable uncontrolled price (CUP) exists for sales gas purposes.

APPEA provided comments that were broadly supportive of key aspects of the proposed approach outlined in the ATO discussion paper. APPEA noted the complexity of the range of factors needing to be considered in determining whether the respective conditions can be satisfied for the existence of comparable prices. APPEA also indicated on a number of occasions the majority of the residual profit split should be allocated to the downstream phase of integrated projects in recognition of the fact that gas is an input not in short supply.

Between 2002 and 2005, further discussions took place between stakeholders, culminating in the finalisation and registration of Petroleum Resource Rent Tax Assessment Regulation 2005 on 19 December 2005.

1.2 1998 Arthur Andersen Review

As indicated above, independent consultants Arthur Andersen were engaged by the Federal Government in 1998 to develop a pricing methodology to establish a gas transfer price for integrated gas to liquid projects for PRRT purposes in Australia. The final report followed a period of extensive consultations that sought to identify the suite of methods that could warrant more detailed assessment in terms determining a preferred mechanism.

The report examined in detail aspects of both the netback and cost plus approaches, including providing commentary on the implications of adopting individual approaches to the calculation of a price. In its final assessment, Arthur Andersen adopted the 'basketing' of the netback and cost plus approaches, referencing international transfer pricing literature. In the context of the profit split, the final report noted:

> *"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.*
>
> *There is no one way of determining a division of the residual price. The following may serve as a guide and are common in the literature on international transfer pricing:*
> - *split based on replicating bargaining in an open market;*
> - *split based on each entities discounted cashflow;*
> - *split based on development expenditures; or*
> - *split based on giving each operation (upstream and downstream) the same return on capital."*

The report examined the practicality of adopting the individual options for determining the profit split, however ultimately concluded the most appropriate and equitable solution was a split of 50:50 between the two phases of the project. Specifically, it was noted that 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."*

The report canvassed in detail the potential design features of the RPM, including testing both its logic and robustness in terms of generated results. Further discussion on the issues canvassed as part of the review is outlined later in this submission.

Arthur Andersen also examined issues associated with adopting a shadow price type model, noting such an approach could use an 'observed' price in an arms-length transaction between unrelated parties as the feedstock transfer price for PRRT purposes. The report identified a range of criteria that would need to be considered before such a price could be established, together with comparability factors that will be relevant in driving price variations in the domestic and feedstock gas markets. In this context, the report also commented on toll processing arrangements, noting an arms-length price would need to meet the range of comparability criteria before a shadow price could be seen to exist.

Overall, the Arthur Andersen report represented an integral element of the Government's detailed response to the issues raised by industry about the need to implement a clear and robust methodology to value gas for PRRT purposes within integrated gas to liquids projects. The RPM model was the final recommended approach.

1.3 Operation of the Gas Transfer Price

1.3.1 The Implemented Model

Outlined below are extracts from the Explanatory Statement (Select Legislative Instrument 2005 No.329) issued by the authority of the Minister for Revenue and Assistant Treasurer in 2005 accompanying the formal release of the PRRT Regulation in 2005. The extracts cover both the operation of the general gas transfer price system and the detail of the RPM.

"*Where there is sales gas of an integrated GTL operation, the Regulations set out the framework for calculating a gas transfer price for that sales gas, and hence the taxpayer's assessable petroleum receipts from the operation for PRRT purposes. This framework is based on arm's length principles. The Regulations specify that, for a taxpayer participating in an integrated GTL operation, the gas transfer price is arrived at in one of the following ways:*

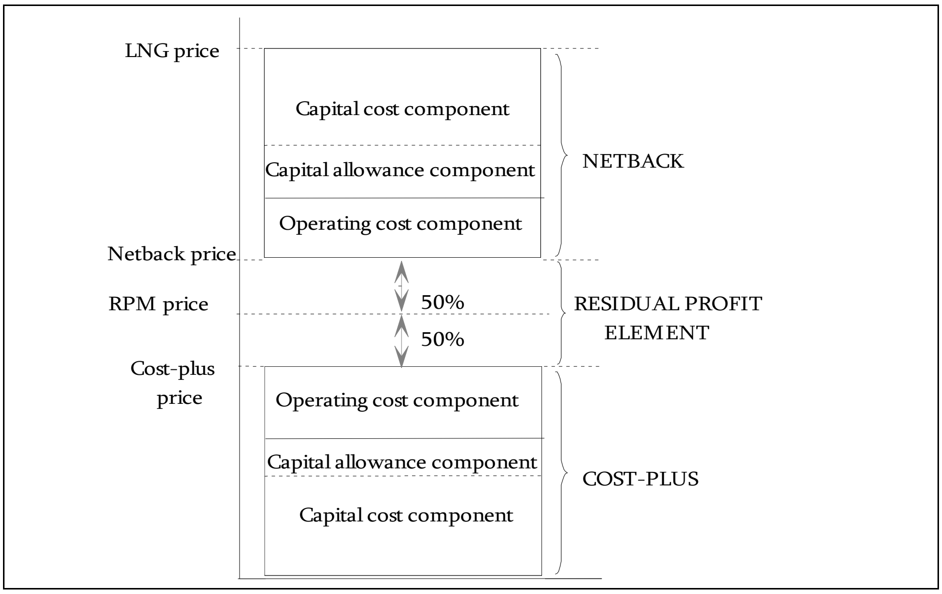
- *An advanced pricing arrangement (APA) between the taxpayer and the Commissioner of Taxation (the Commissioner). This involves the taxpayer and the Commissioner agreeing on a gas transfer price (and the associated methodology to determine this price) in the context of the particular project.*
- *If there is no APA, a comparable uncontrolled price (CUP) is used to determine the gas transfer price. A CUP is a price that can be observed in the relevant market place for the sale of sales gas in an arm's length transaction and that is applicable to the particular project.*
- *If there is no APA or CUP, the residual pricing method (RPM) as outlined in the Regulations is used to determine the gas transfer price. The RPM uses an arm's length methodology to work out a gas transfer price that is ordinarily the average of the cost-plus price and the netback price. The RPM is a safe harbour for taxpayers and the Commissioner to determine a price for sales gas.*
- *Where there is no APA and no CUP and where the taxpayer has insufficient information to use the RPM, the Commissioner and the taxpayer can agree on a gas transfer price. If the Commissioner and the taxpayer cannot agree, the Commissioner can set a fair and reasonable gas transfer price.*

If sales gas is not processed into, or used in the production of, project liquid in an integrated GTL operation, then assessable receipts for the sales gas are worked out in the same way as for any other petroleum or marketable petroleum commodity. In that case, the assessable receipts will be based on the fair market value of the sales gas if it is not sold, or on the consideration that would be given at arm's length if it is sold other than arm's length.

Besides setting the approach used to determine the gas transfer price, the Regulations are primarily devoted to the method of calculation of the gas transfer price using the RPM approach. That is, the Regulations provide a step-by-step methodology to calculate the cost-plus and netback prices — and consequently, the gas transfer price — for an integrated GTL operation.

The cost-plus price is the calculated minimum price the upstream stage of an integrated GTL operation sells its sales gas for in order to cover its upstream costs as defined. The netback price is the calculated maximum price paid for sales gas that allows the downstream stage of the integrated GTL operation to cover its downstream costs as defined, and given the price obtained for project liquid. In both cases, the calculations allow for a rate of return on capital costs incurred. In general, the gas transfer price is equal to the netback price and the cost-plus price, divided by two. This is illustrated in Figure 1. However, if the netback price is lower than the cost-plus price, the gas transfer price is the netback price.

Figure 1: Stylised representation of the RPM



The Regulations also provide a basis for determining which costs are relevant to the RPM calculation and whether, and to what extent, they fall in the upstream or downstream stage of the project.

****

The Regulations also recognise that an integrated GTL operation may be used to process gas from more than one petroleum project, and may produce other products as well as project liquid. When this occurs, the Regulations allow for the capital costs associated with those parts of the operation used to process gas of more than one petroleum project or produce more than one product to be apportioned. This means that the RPM price only reflects the share of the costs associated with producing project liquid from project natural gas."

1.3.2 Subsequent Amendments

Amendments to the 2005 Regulation were made in 2013 and 2015 with a view to responding to a number of changes impacting on the operation of the gas transfer price. The changes are outlined below and are primarily technical in nature.

2013 Changes

The changes were intended to adapt and extend the existing framework so that it could be applied to onshore gas to liquids operations and the North West Shelf LNG project. The 2012 changes to the operation of the PRRT extended the scope of the tax to cover both onshore and NWS operations, necessitating a change to the scope of the Regulation. The Regulation was also extended to cover integrated gas-to-electricity (GTE) operations.

In summary, the 2013 changes:
- Ensured that the framework in the Principal Regulation for determining assessable petroleum receipts in relation to an integrated GTL operation applies to onshore GTL operations, including those utilising coal seam gas, as well as the North West Shelf LNG project;
- Ensured that the framework in the Principal Regulation for determining assessable petroleum receipts in relation to an integrated GTL operation is able to appropriately apply to integrated GTE projects;
- Allowed taxpayers to make an election to apply the Residual Pricing Method (RPM) in relation to onshore integrated GTL projects as the default method for determining assessable petroleum receipts;
- Gave taxpayers the option of using mass rather than volume measurements for project products to determine an RPM price, in order to reduce compliance costs for integrated operations who measure by mass; and
- Provided taxpayers holding an interest in an integrated GTL project that existed prior to 2 May 2010 (that is, the North West Shelf project) with a simplified RPM for determining the value of project sales gas.

<u>2015 Changes</u>

The 2015 amendments introduced minor changes to modernise the drafting style contained in the original Regulation, sought to reduce compliance costs and ensured that the Regulation remained fit-for-purpose.

In summary, the 2015 changes:
- Allowed taxpayers to jointly make an election for an onshore integrated gas-to-liquid operation to aggregate the relevant costs into one upstream phase and allowed an election for an onshore integrated operation to use the depreciated replacement cost method for the purposes of the RPM.
- Allowed taxpayers to jointly make an election to use the value of their own share of the end products as a component of the netback price in specified circumstances.
- Added an example to clarify that the Commissioner of Taxation's power to agree to or to determine an RPM price can be used when required information is not available.
- Corrected the inconsistent treatment of storage costs for project sales gas in an integrated operation so that the cost for storage of sales gas is treated as a downstream cost.

Other than the minor changes implemented in 2013 and 2015, the Regulation has remained largely unchanged. The RPM's formulaic approach in determining a price at the taxing point has presented both investors and administrators with greater predictability for what are often relatively marginal projects. This compares with the practical and operational challenges associated with seeking to use comparable prices (see Section 2 for a discussion of comparable prices).

1.4 2017 Callaghan Review into the Operation of the PRRT

> *"It is not evident from the submissions, however, that there are workable alternative arrangements readily available which will result in improved outcomes. Moreover, recognising that the existing GTP arrangements were developed in close consultation with the industry, and taking into account the long investment cycles of integrated LNG operations and the substantial investment that has taken place based on existing arrangements, any change in the approach to calculating transfer prices would require careful consideration and should be undertaken in consultation with industry. Any in depth review of GTP could examine whether the current arrangements are consistent with the latest transfer pricing practices and whether particular elements should be changed, such as the notional loss situation, the appropriate way to split profits and the appropriate rate to use for the capital allowance."*
>
> Callaghan Report, p.94

A review was commissioned in late 2016 by the Federal Government into petroleum resource taxation in Australia, with the final report being released in mid-2017. The process was led by Mr Michael Callaghan AM PSM, and while the review examined all aspects of the federal petroleum resource taxation system in Australia, the main focus covered the operation of PRRT. A series of recommendations were made, some that were limited to new projects, with others being focused on new and existing projects. Recommendations associated with the PRRT gas transfer pricing provisions were limited to new projects.

As noted in the Treasury Consultation Paper, the Callaghan Review recommended that the existing GTP regulations be examined to identify changes that would achieve greater simplicity and transparency, ease of compliance and a fair treatment of the economic rent generated from each stage of an integrated petroleum operation. Specific issues contained in the review covered the following:

- revisiting the potential use of a CUP as the primary method of setting the gas transfer price in line with international best practice and recent work undertaken by the Organisation for Economic Co-operation and Development (OECD); and
- where a CUP is not available, examining the appropriateness of the asymmetric treatment of upstream and downstream operations, the way profits are split between upstream and downstream, and the rate of the capital allowance in the RPM.

The Review also addressed the criticisms made by external stakeholders about its operation, noting they broadly fall into three categories:

- Whether a price for sales gas is required at all. Some submissions advocated moving the taxing point to the end of the LNG production process by, for example, using the free on board price for LNG as the taxing point.
- Whether a 'transfer price' is the best method for establishing the price for sales gas in an integrated project.
- Whether the methodology used for establishing a transfer price is appropriate.

Each of above were dealt with either directly or indirectly within the Callaghan review.

Contrary to commentary in the Treasury Consultation Paper that the gas transfer price regulations '*likely undervalue gas that is used in vertically integrated LNG or electricity generation projects compared to what an arms-length market price for sale gas would be'*, the Callaghan Review adopted a more objective approach, commenting on the actual provisions and suggesting areas that could warrant a revisiting. No evidence was provided about the undervaluation of assessable receipts, as suggested in the Treasury Consultation Paper.

The Callaghan Report made a number of other observations that are highly relevant in the context of any consideration of the gas transfer price provisions, as contemplated as part of the Treasury review.

With respect to adopting a simple netback method for valuing gas:

> "*Likewise, changing the RPM to rely on the netback price only (thereby allocating all project profits to the upstream) would mean that project risks are no longer equitably reflected on all costs centres. The result would be that any rents attributable to the downstream would be captured in the upstream and subject to PRRT.*" (p92)

With respect to whether a comparable uncontrolled price exists:

> *"The LNG operations in North West Australia present a different challenge to establishing a CUP. Some of the operations do not sell gas to the domestic market, meaning the price of sales gas is not observable. Where sales gas is sold it is sold under WA's domestic gas reservation policy, resulting in a price for the sales gas that is not comparable. These differences mean that there are no observable or comparable market based transactions available to establish a price for sales gas.* (p90)

In terms of the taxing of rents:

> *"Given that the PRRT is a resource rent tax, the pricing of sales gas under the GTP regulations should result in the PRRT taxing those resource rents that are properly attributable to the associated petroleum resource. Similarly, it would be inappropriate for project profits properly attributable to the downstream LNG processing operation to be captured within the PRRT if the intention of the PRRT is only to capture the resource rents associated with initial processing of sales gas. The allocation of resource rents associated with integrated LNG projects is, however, an issue of some contention."* (p.90)

The comments in the remainder of this submission are directed at individual issues raised in the Treasury Consultation Paper and the Callaghan Report.

Section 2: Comparable Prices – Do They Exist?

> *"The preferred option for implementing the policy objective is to include a methodology to determine a GTP. The shadow pricing methodology can only be used where there is an observable comparable arm's length price. It is not expected that the shadow pricing method could be reliably applied in the foreseeable future."*
>
> Explanatory Memorandum, Tax Laws Amendment Bill No. 6 2001

The Consultation Paper raises a number of issues associated with the potential existence and application of comparable uncontrolled prices (or CUPs) for feedstock gas. The gas transfer price methodology contemplates the use of a CUP where such a price is observable. In practice, a CUP is a price that can be observed in the relevant market place for the sale of sales gas in an arm's length transaction and that is applicable to the particular project. **APPEA is of the view that comparable prices do not presently exist, and the likelihood of prices existing in the future is highly unlikely**.

2.1 Offshore Petroleum Resources and Projects in Australia

> *"The LNG operations in North West Australia present a different challenge to establishing a CUP. Some of the operations do not sell gas to the domestic market, meaning the price of sales gas is not observable. Where sales gas is sold it is sold under WA's domestic gas reservation policy, resulting in a price for the sales gas that is not comparable. These differences mean that there are no observable or comparable market based transactions available to establish a price for sales gas. Despite this, it would be appropriate to continue to pursue the option of establishing a shadow price or CUP across the LNG projects and align the approach to establishing a CUP to the latest OECD recommendations and approaches on transfer pricing. The market conditions and project structures could be regularly reviewed to determine whether it is appropriate to establish an industry wide CUP that would take the place of the RPM as the main GTP methodology for LNG projects."*
>
> Callaghan Report, p.90

This submission will further discuss the criteria that need to be considered to ascertain whether a CUP exists. In the context of a more detailed discussion, it is important to understand the nature of offshore petroleum resources and projects in Australia to allow for a meaningful benchmarking to be undertaken using the relevant criteria. This discussion is intentionally limited to offshore resources and activities due to the decision by Parliament to enact changes to the PRRT regime in early 2019 removing the onshore industry from the scope of the tax from 1 July 2019.

Features of the offshore gas industry include the following:

- **Location**: Unlike competing gas resources in countries like the United States, Indonesia and in the Middle East, significant gas resources are located offshore and, in some cases, hundreds of kilometres from land. The costs associated with pipeline transport to shore-based LNG plants are high on a per kilometre basis and often vary significantly from project to project.
- **Water Depth**: Some of the gas fields lie in very deepwater, in depths nearing 1000m. The development of such resources require high cost and often bespoke technologies with high technical and commercial risks.
- **Gas Quality**: The presence of CO_2 and inert gases at significantly varying levels across different fields results in disparate development costs due to additional gas processing and gas reinjection requirements.
- **Condensate Ratio**: The presence of condensate (gas liquids) in a gas resource can add substantial value to a project where the condensate revenue streams are sufficient to cover the

incremental liquid-stripping investment. Condensate ratios vary significantly across fields and projects.

- **Reservoir Quality:** The areal extent, thickness and faulting of individual gas reservoirs, together with the ease at which gas can flow through the reservoir determines the number and complexity of production wells required to drain the gas from a field. These "subsea development costs" comprise a significant proportion of project costs. Some resources are characterised by high subsea development costs due to poor reservoir quality.
- **Development Concepts:** Individual geological and geographical features necessitate different development concepts. A range of different infrastructure solutions exist in offshore Australia, ranging from conventional fixed platform structures to integrated floating LNG (FLNG) solutions.
- **Remoteness from Domestic Markets**: The growth of energy-based projects in locations such as the Pilbara have created niche local markets for a relatively small proportion of the currently identified static gas resources. Domestic markets for the majority of the gas resource presently do not exist.
- **Market Intervention:** As noted in the Callaghan Report, domestic gas market interventions in the west coast market through the imposition of the so-called ‘domestic gas reservation policy’ acts in a manner that leads to non-comparable outcomes because the price and volume of gas available is not only controlled by the influences of supply and demand, but also by government intervention.

Overall, the defining feature of the offshore gas industry is that no two resources or projects are identical.

2.2 Factors Determining the Existence of Comparable Prices – ATO Position

> *“Although this method is potentially available for all types of transactions, the product comparability requirement to be able to apply it in a reasonably reliable manner is especially high, because any product difference may materially affect the price of the transaction, while it is often not practicable to make reasonably accurate comparability adjustments for such differences.”*
>
> OECD July 2010

In determining whether a CUP for offshore sourced feedstock gas exists (either at a single point in time or on a continual basis), an important consideration is the question of what constitutes an arms-length transaction.

A discussion paper was prepared by the ATO in 2000 that sought to aid discussions around developing the details of gas transfer price arrangements. The ATO outlined their views on what constitutes ‘arm’s-length’ as follows:

> *“An arm's-length transaction will mean a transaction where the parties to the transaction are dealing at arm's-length with each other in relation to the transaction. In determining whether an arm's-length transaction has occurred, regard will be given to "any connection between" the parties to the transaction or to "any other relevant circumstances".*
>
> *The Commissioner's existing income tax rulings, for example Taxation Ruling TR 94/14, that considers the application of Division 13 of Part III of the Income Tax Assessment Act 1936, provide the Australian Taxation Office (the ATO) interpretation of the expression "dealing at arm's-length with each other" as used in those provisions. The Taxation Rulings can be used as a guide as to the meaning of this expression for the purposes of the Act.*

> *In a GTL project, there may be uncertainty, or a dispute may exist with the Commissioner, about whether an arm's-length transaction has occurred. In these circumstances, the Commissioner will determine whether an arm's-length transaction has taken place."*
> (Australian Taxation Office, 2000)

This context is significant as it is clear the ATO considers normal arm's-length guidance and interpretative material should form the basis for a key element of the assessment of whether a CUP exists for feedstock gas.

It does not contemplate the adoption (or appropriateness) of an alternative approach, and would therefore seem to be inconsistent with a suggestion expressed in the Treasury Consultation Paper that canvasses the option of modifying the established criteria to effectively 'manufacture' a modified CUP for PRRT purposes.

Indeed, adopting a modified or 'manufactured' CUP has the real potential to fundamentally undermine the integrity of the PRRT regime, creating a heightened level of uncertainty and subjectivity that was never considered or contemplated when the gas transfer price provisions were developed. Such an outcome would clearly have significant consequences for the ability of taxpayers to make long term investment decisions with any degree of confidence.

2.3 Comparable Prices for Offshore Feedstock Gas in Australia – Independent Analysis

> *"In the event a potential CUP can be identified, the likelihood of the comparability factors being satisfied is limited, due to the complex nature of the industry. The broader industry determinants which significantly impact the comparability of transactions as well as the factors which impact the price between feedstock gas and domestic gas result in the limited application of CUPs in the context of the PRRT legislation."*
>
> Deloitte Report to APPEA

APPEA commissioned advisory firm Deloitte to undertake a detailed review of the factors relevant in determining the existence of CUPs for feedstock gas in offshore gas to liquids projects in Australia. Deloitte has significant expertise in the area of transfer pricing and a deep understanding of the Australian gas industry. A copy of Deloitte's report is at Attachment 1.

In summary, Deloitte concluded that even if CUPs could be identified, performing the necessary comparability adjustments to enhance the reliability is particularly challenging. It was noted that while the CUP method could be applied to other industries, there are a significant number of practical challenges to the application of CUPs for determining an arm's length price for feedstock gas in Australia.

It was also noted that it is important to differentiate between LNG sales and feedstock gas. LNG sales are very different in nature to feedstock gas, as LNG sales take place at a later point in the supply chain. It is furthermore important to consider the value add contributions that are made to the product from the point of feedstock gas to LNG, which are considered to significantly impact on the LNG price.

The report also comments on the RPM as a methodology in determining the gas transfer price. It is noted that there are significant advantages in using the RPM as it does not rely on both identifying and adjusting external transactions, but instead allocates a return for the standard upstream and downstream activity and then divides the remaining profit. This method allows both the upstream and downstream stages to participate in the residual profit, noting these projects involve integrated economic activities. Deloitte concludes the RPM as a method has close alignment with the OECD Profit Split methodology.

Presented below are a series of comments and extracts from the Deloitte report that highlight a number of the key findings. Further details are available in the final report which is attached to this submission.

2.3.1 General Observations

The CUP method is a particularly reliable method where an independent enterprise sells the same product (i.e. in an uncontrolled transaction), in the same circumstances as is sold between two associated enterprises (i.e. a controlled transaction). It may be difficult to find a transaction between independent enterprises that is similar enough to a controlled transaction such that there are no differences which have a material effect on price. For example, a minor difference in the property transferred in the controlled and uncontrolled transactions could materially affect the price. When this is the case, adjustments will be required to the extent they are able to be performed. The extent and reliability of such adjustments will affect the relative reliability of the analysis under the CUP method.

In considering whether controlled and uncontrolled transactions are comparable for purposes of the CUP method, regard should be had to the effect on price of broader business functions other than mere product comparability (i.e. all of the factors relevant to determining comparability as listed in Appendix D). Where differences exist between the controlled and uncontrolled transactions or between the enterprises undertaking those transactions, it may be difficult to determine reasonably accurate adjustments to eliminate the effect on price. The difficulties that arise in attempting to make reasonably accurate adjustments should not routinely preclude the possible application of the CUP method. Every effort should be made to adjust the data so that it may be used appropriately in a CUP method.

2.3.2 Comparability Factors/OECD Guidelines

In the event a transaction can be identified as set out above, assessment would then need to be made of whether the comparability factors are met with respect to the potential CUP.

The GTP framework set out in the PRRT Regulation is based on arm's length principles. For the purposes of the PRRT Regulation, a transaction is defined to be non-arm's length if the Commissioner, having regard to any connection between the parties to the transaction or to any other relevant circumstances, is satisfied that the parties to the transactions are not dealing with each other at arm's length in relation to the transaction. The definition is rather unhelpful and it leaves the term 'arm's length' open to interpretation. This formulation is, however, similar to that found in the former Division 13 of the Income Tax Assessment 1936.

Section 23 of the PRRT Regulation defines a CUP for the purposes of the PRRT Regulation as a price determined in a market that the Commissioner is satisfied is a relevant market, and that the Commissioner is satisfied is an observable arm's length price. Direction is given in subsections 23(3) and 23(4) about what factors must be taken into account in determining whether a market is relevant. These regulatory factors provide a framework for consideration of a CUP, which may be seen to be a minimum requirement. Further guidance is not contained in the PRRT Regulation and therefore the OECD approach to CUPs may be considered to be the appropriate guidance material given its international acceptance as the basis for determining arm's length pricing between associated entities.

The authoritative nature of the OECD Guidelines for income tax purposes has been established through its pervasive and global use in related party matters in Australia and internationally, as a consensus based framework agreed by OECD member nations. Subdivision 815-B of the Income Tax Assessment Act 1997 explicitly directs taxpayers to use these guidelines to determine arm's length prices. While the interpretation of the PRRT legislation ought to be discerned from the terms (including the text, context and purpose) of the legislation alone (as income tax law and, by implication, OECD guidance do not govern the interpretation of the PRRT law), its structure by comparison can highlight points of difference. Further, the PRRT Regulation does explicitly reference internationally accepted transfer pricing principles.

In addition, both State and Federal revenue authorities (by way of one example, in the context of State Royalty Projects) have relied, and continue to rely, on the OECD Guidelines for non-transfer pricing matters. Therefore, it appears reasonable to assume that in practice arm's length pricing methods, as recognised in ATO and OECD transfer pricing guidance, are relevant as points of reference or comparison in applying the arm's length principle for purposes of the PRRT Assessment Act and the associated PRRT Regulation. It can be reasonably concluded that observations obtained by using an appropriate arm's length pricing method in accordance with transfer pricing guidance, would provide a point of reference or comparison (if not a starting point) to assess the requirements in the PRRT Assessment Act and the associated PRRT Regulation.

Furthermore, Section B.1.8 of the Callaghan Review states that it would be appropriate to align the approach to establishing a CUP to the latest OECD recommendations and approaches on transfer pricing.

The below table sets out the comparability factors, in order of importance, which must be considered under the OECD Guidelines in order to determine whether a CUP exists. Note, the comparability factors in the PRRT Regulation overlap with those set out in the OECD Guidelines therefore consideration of the OECD Guidelines comprehensively encompasses the requirements of the PRRT Regulation. The table also provides examples of differences between controlled and uncontrolled transactions that are commonly observed in the industry, which often preclude the possible application of the CUP method.

The below table is not exhaustive however it highlights various industry specific factors which impact the assessment of whether a CUP exists. The table also demonstrates how differences between controlled and uncontrolled transactions may be too significant (such that no CUP exists), or such differences may not be able to be reliably adjusted for which would again preclude the reliable application of the CUP method.

Comparability Factors	**Examples**	**Explanation**
1. Characteristics of property	Rich vs lean	It is generally accepted that specifications of gas are comparable. An exception to this are the recognised differences between 'rich' gas as compared to 'lean' gas, which has a lower calorific value. Where this difference exists, reasonably accurate adjustments would be required to ensure comparability.

2. Functions, assets and risks	Ultimate customer (export vs domestic)	The OECD's Actions 8-10 Reports reinforce the critical importance of requiring a similar functional profile to ensure comparability. Feedstock gas should not be considered comparable to domestic gas, on the basis that there is a very different functional profile for the value chain of each gas. The value chain of LNG projects (feedstock gas) require significantly more capital assets (e.g. pipelines, liquefaction plant, access to shipping/terminals, marketing intangibles specific to overseas markets). LNG projects also need additional functions to be undertaken in order to ensure sale to the ultimate export customer (e.g. midstream / downstream processing, management of shipping, maintenance of customer relationships). Finally and most importantly, the significant additional risks present in the LNG value chain (e.g. shipping risk, currency risk, damage to assets, sovereign risk, liquefaction plant operating reliability risk) are not comparable to domestic gas. The potential for reasonably accurate adjustments for such significant deviations is limited.
3. Contract terms and conditions	▪ Oil-linked pricing ▪ Volume ▪ Duration ▪ Assignment of risk	Feedstock gas is converted into LNG, which is ultimately priced with reference to published oil indices and therefore is subject to different market factors, for which it is difficult to make reasonably accurate adjustments. Volume discounts are financial incentives provided to encourage buyers to purchase larger quantities and are often observed in the commodity sector.29 Additionally, securing offtake (purchase) for a longer duration may also attract a discount, particularly in an industry which commonly observes 20-year purchase agreements as well as short-term offtakes. Both of these examples necessitate reasonably accurate adjustments. Allocation of risk in contracts can differ greatly (e.g. Incoterms for LNG, performance risk, take or pay) and depending on the specific difference, may not be able to be adjusted for.

4. Economic conditions	▪ Government intervention ▪ Propensity for distressed buyers / sellers to exist ▪ Geographic ▪ Ultimate customer (export vs domestic)	Government intervention in the domestic gas market can result in unquantifiable change in the economics of the market. Ensuring supply into the domestic gas market or prohibiting exportation of LNG may result in the price not being indicative of market driven pricing because the transaction may not be undertaken on a profit maximising basis. In a distressed purchase / sale, the price of the product purchased / sold can be considered somewhat artificial as it was not sold under open and competitive market conditions. Normally this requires a willing but not anxious buyer and seller. The gas market, both domestically and abroad, has on occasion experienced these adverse market conditions.30 The demand from particular geographic regions, whether domestic (East coast vs West coast) or abroad (China vs Japan) can influence and affect the prices paid in transactions. Given that the market is significantly different for domestic gas as compared to feedstock gas, the economic conditions comparability factor is not usually satisfied and it is difficult to determine the impact on price of these varying economic conditions.
5. Business strategies	FID	Factors of importance to the business can significantly impact the price agreed for a transaction. Particularly for LNG Projects approaching FID, securing supply is of utmost importance and can result in the buyer having greater bargaining power to secure a lower price. By securing the lower price the business is able to increase its probability of reaching FID and ensuring the success of the project, which is difficult to value.

To apply a CUP method to determine the amount of the assessable petroleum receipt in respect of feedstock gas at the taxing point, it would be necessary to identify a transaction with:

- Prices charged by the selling entity in the same or similar transactions with an independent party (‘Internal CUP’);
- Prices paid by the purchasing entity in the same or similar transactions with an independent party (Internal CUP); or
- Prices paid in the same or similar transactions between two independent third parties (‘External CUP’).

There are observed difficulties in identifying both types of CUPs, due to the nature of the Australian gas industry and the structure of Australian gas projects. Given that most Australian LNG projects that produce feedstock gas are owned and operated by a single entity or joint venture group, it is difficult to identify any feedstock gas transactions (either sales to third parties or purchases from third parties) to assess as a potential Internal CUP.

Furthermore, there is currently no observable market for feedstock gas transfers that could be relied on to identify transactions that may constitute an External CUP. Most Australian gas projects are expected to operate for a number of decades and therefore it is unlikely that projects will become less operationally integrated or economically interdependent. This supports the industry view that potential CUPs are unlikely to exist in future years as well.

Additionally, due to the limited competition and protection of proprietary information within the Australian gas industry, it is also difficult to identify External CUPs. In the rare event that potential External CUPs can be identified, there are still the difficulties in satisfying the comparability factors and/or performing reliable adjustments to account for such differences.

2.3.3 Adjustments

The above table addressed the difficulty in making adjustments to a potential CUP. Two considerations should be made when determining whether a reasonably accurate adjustment can be made

1. is the adjustment reliable and robust; and
2. is the adjustment sustainable if applied on an ongoing basis.

Deloitte observed in negotiations with the Australian Taxation Office on transfer pricing Advance Pricing Arrangements ('APAs') where a potential CUP has been identified, the application and calculation of necessary adjustments often cannot be agreed upon. The complexities arising from ensuring that any such adjustments are reliable and able to be made year on year has created significant road blocks in negotiations.

Being able to make reliable adjustments is difficult for a number of the examples above. Quantifying the value of the difference is often not an exact science and may undermine the application of the CUP entirely.

Some adjustments observed in the industry are for: volume, duration, timing and shipping. However, based on our industry experience, being able to adjust for qualitative factors such as economic conditions or business strategies is significantly harder.

Given that PRRT is an annual tax, consideration must be given to whether the adjustment can be applied over multiple years. Some adjustments may need to be calculated on a year on year basis and this creates additional complexities in ensuring the reliability of the adjustment.

Recent landmark transfer pricing cases have acknowledged that identifying a CUP goes beyond finding the same or similar product. The judgement provided in the *SNF (Australia) Pty Ltd v Commissioner of Taxation [2010] FCA 635* case acknowledged that identifying a CUP extends to ensuring that those factors which may influence price (i.e. those included in the OECD Guidelines as the comparability factors) must be the same or reliably similar.

The ATO has publicly expressed its concerns on taxpayers' attempts to apply the CUP method, in the context of commission rates. The ATO states that the comparability standard to establish reliability is higher when applying the CUP method. The ATO's concern is that an absence of information to evidence the comparability of the uncontrolled transaction may result in merely demonstrating that a 'similar' transaction exists, rather than a 'comparable' transaction. The ATO notes that the comparability standard should be met with reference to the OECD's comparability factors.

Following the release of the OECD's Actions 8-10 Reports, the OECD Guidelines recognised that a 'quoted price' could be relied on to determine an arm's length price for commodity transactions. However, there are no quoted prices for Australian domestic gas or feedstock gas. If there are CUPs they are negotiated confidentially and not available in the public domain and therefore not able to be relied on.

Internal CUPs are often considered for potential application as it is generally easier to obtain the additional information required to confirm whether the comparability factors are met between the controlled and uncontrolled transactions. However, as always, the application of an Internal CUP is subject to the particular facts and circumstances of the transaction. In the gas industry there are a number of industry factors, which can significantly impact the price, but which are difficult to quantify and reliably adjust for.

2.3.4 Conclusion

In summary, there is little likelihood of a CUP existing either now or in the near future. The prevalence of differences that preclude the application of a CUP in the gas industry is observed to be relatively high, when compared to other industries.

Furthermore, making adjustments to the potential CUP is extremely difficult due to the complex nature of the adjustments and industry. When considering the reliability and sustainability of such adjustments it is likely to result in possibly undermining the identified potential CUP. The OECD Guidelines recognise that the need to perform numerous or substantial adjustments to key comparability factors may indicate that the third party transactions are in fact not sufficiently comparable.

Deloitte's experience is that the CUP method is of limited use for PRRT application due to the difficulty in:

- Identifying potential CUPs (both Internal and External CUPs);
- Satisfying the requisite comparability factors; and/or
- Making reasonable reliable adjustments to satisfy the comparability factors.

2.4 Tolling and Observable Prices

The Consultation paper poses a number of questions associated with the connection between tolling arrangements and arm's length prices. A tolling arrangement for LNG purposes represents an arrangement where an upstream resource owner and processing infrastructure owner negotiate an agreement which delivers value to both parties.

The terms of any commercial agreement that is negotiated will in each case ultimately depend on the full negotiating position of each party, which would include for example:

- location of resources/infrastructure
- availability of alternative resources/infrastructure
- the age of the infrastructure
- the economic position and portfolio of each party

It is the range of these factors which make it difficult to apply a CUP, even in a tolling environment. In addition, adjustments would need to be made to account for the difference between the taxing point, and the tolling point of receipt. The 50/50 profit split in the RPM remains an appropriate proxy methodology, such that the detailed bargaining position of the parties does not need to be considered and taken into account.

A key driver of the significant investment in LNG infrastructure in Australia over the past decade is the large scale of gas reserves in Australia, many of which remain undeveloped. The value of an LNG train is maximised when it remains at or close to its processing capacity. It is therefore contemplated from the outset that as ullage arises when gas from the initial reserve starts coming off plateau, that other resources or infill will be available to be processed through the plant to keep it at capacity.

The investment case for a downstream facility is therefore underpinned by a long term view that sufficient gas will continue to be available to process. To consider a single tolling agreement in isolation does not take account of this long term view and the complex commercial drivers of the parties.

Section 3: Operation of the Residual Price Methodology

> *"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). The operation of RPM may be summarised in very broad terms in three stages. First, a specified return (or capital allowance) on upstream capital and operating costs for the year directly determines the upstream gas price and thereby the 'cost-plus' measure of upstream gross receipts (price times volume). Secondly, the same specified return (capital allowance) applied to downstream capital and operating costs for the year determines downstream gross receipts which are subtracted from known overall gross receipts from LNG sales to give a 'netback' measure of upstream gross receipts. Finally, the RPM measure of upstream gross receipts, subject to PRRT, is the average of the cost-plus and netback measures."*
>
> Callaghan Report, p.88

The gas transfer price represents a key contemporary component of the PRRT regime. As noted in Section 1, it was developed following a lengthy period of discussion between government and industry, with the intention to formulate both an efficient and equitable pricing mechanism. It is administered by the ATO in collaboration with individual taxpayers to take into consideration the factors relevant to individual projects. The ATO generally has a high level of engagement with individual project proponents in the operation of the provisions.

The Treasury Consultation Paper raises issues associated with the design and operation of the RPM. A number were discussed within the Callaghan Report as warranting review to ensure they remain fit for purpose. Many were specifically considered as part of the 1998 Arthur Andersen review.

As a more general observation, APPEA would note the Treasury Consultation Paper suggests that the RPM creates a 'notional' integrated operation as the basis for determining the relevant gas price. We consider this fundamentally misunderstands the purpose and operation of the RPM. The design of the RPM is unique as it determines a price based on actual project cost data. As such, it provides a more accurate basis for estimating or determining a price compared with alternatives that may exist, including through arbitrarily modifying or adjusting an observable price (if one exists).

The discussion surrounding the detailed operation of the RPM is important as little evidence exists to support the case for the existence of a CUP or comparable shadow price (as demonstrated in Section 2 of this submission).

3.1 The Residual Profit Split

<u>Development of the 50/50 Profit Split</u>

> "*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.*"
>
> Australian Taxation Office, December 2000

The gas transfer price model announced by the Government in late 1998 was considered to be the superior approach for determining a price for feedstock gas within an integrated gas to liquids project.

Within the RPM, a key component is the allocation of 'profit' between the upstream and downstream phases of a project. The approach finally adopted provides for an equal (50/50) apportionment of any residual amount (or profit) between the upstream and downstream phases. Arthur Anderson in their report noted the following:

> *"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."*
>
> Arthur Andersen Report, p23-25

The Department of Industry, Science and Resources reaffirmed this view in 1999 in advice to APPEA, indicating the 50/50 profit 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."*
>
> Department of Industry, Science and Resources, 25 May 1999

As part of the Arthur Andersen review, it was noted that a key threshold question related to the allocation of rent between the upstream and downstream segments of an integrated project (assuming rents exist). This is important because the PRRT is designed to only tax rents up to the point where a marketable petroleum commodity is deemed to exist (that is, it is a tax on the underlying resource). While this is broadly achieved within the mechanics of the PRRT legislation by denying taxpayers the ability to deduct costs incurred after the taxing point, it is also necessary to ensure that the price at the taxing point reflects the correct allocation of rents.

> *"A key issue in determining the gas transfer price in an integrated gas to liquids project is the effect it has on the allocation of economic rents upstream and downstream. This is a*

> *critical issue because the PRRT legislation has the express intent of only taxing rents accrued upstream."*
>
> 1998 Arthur Andersen Report, p.20

The Arthur Andersen review examined a variety of options that could conceptually be used to allocate the residual profit between the different phases of an integrated projected. The options identified were splits based on the following criteria:

1. replicating bargaining in an open market;
2. based on each entities discounted cash-flow;
3. based on development expenditures; or
4. giving each operation (upstream and downstream) the same return on capital.

Each of the options were considered.

Option 1 was dismissed as it is difficult to determine a reliable mechanism for splitting the price based on open market bargaining. The relative market power of the upstream and downstream is indeterminate because no similar market auctions are observable.

Option 2 was not considered appropriate in the context of the gas transfer pricing discussion as the upstream part of a project has no cash-flows, apart from gas sales which is determined by the transfer price.

It was acknowledged that *Option 3* could provide an indication of the relative contributions to an integrated operation, however this would be limited to situations where there is a close connection between cost and the value generated. Arthur Andersen's were of the view that in the context of an integrated gas to liquids project, it is not clear that there is necessarily a strong relationship between costs and the residual value. As highlighted by the Department of Industry, Science and Resources, the residual value is likely to come from elements such as resource scarcity, ease of extraction, intellectual property and know how in terms of gas production, processing and marketing.

Apportioning residual profits as per *Option 4,* whereby each part of the project is given the same return on capital, was rejected as capital expenditure is not the factor which is driving the residual price.

The report prepared for APPEA by Deloitte into CUPs briefly discusses the RPM. It was noted that the RPM represents a hybrid of two commonly used OECD pricing methods (the cost plus and the resale price methods). The 50/50 split adopted at the time the RPM model was announced reflected the fact that there was minimal experience to draw on and an equal split was the most equitable and objective way to reflect both the inter-dependent and integrated nature of gas to liquids operations. The following observation is made:

> *"Although the Callaghan Review highlighted that the residual profit element could be more accurately apportioned, the method itself remains in line with recognised OECD methods and is necessary as an alternative, when CUPs and APAs are not in place. The RPM also recognises that Australian gas projects are highly operationally integrated and economically interdependent, which necessitates the application of a method that recognises these industry factors."*
>
> Deloitte Report to APPEA

Value in the LNG Price Chain

> *The concept of rents is an important consideration under a netback approach. Traditionally rents receive explicit treatment as a quantifiable rate in a netback formula. These downstream rents are usually factored into the capital cost parameters used in netback calculations. Such an approach is contentious because it implies that a vertically integrated LNG project's rents can be allocated to separate stages in the value chain. The argument that total project rents are so closely interdependent of both its upstream and downstream activities that such an allocation of rents is unfeasible is a frequently cited drawback of this method. Furthermore netback requires the level of rents to be predetermined. This is problematic if the level of rents vary with the project's life.*
>
> Arthur Andersen Report, p.11

To assist in understanding both the linkages and value creation within integrated gas to liquids projects, APPEA sought the advice of consulting firm Wood Mackenzie. Wood Mackenzie is a global energy consultancy group that has work with governments, industry and other stakeholder groups over a number decades.

Wood Mackenzie's advice was sought in relation to value creation in the LNG chain and how the LNG industry's evolution over the last 20 years may or may not have materially impacted the validity of the existing profit split under the RPM. A copy of Wood Mackenzie's advice is at Attachment 2. The Wood Mackenzie report drew a number of conclusions that are presented below.

Value Creation in the LNG Process

- "The LNG value chain is significantly more complex than a typical upstream gas value chain (eg pipeline gas). LNG projects require large, upfront investments in additional processing facilities (liquefaction), transportation and marketing activities to get the upstream gas to a point of sale. These accumulate significant additional costs and risks which need to be compensated so a project can pay back on its investment and generate profits."

- "Value is ordinarily created at every stage of the LNG process: from upstream production; to pipeline transportation; to processing and liquefaction; to shipping; to storage; to regasification; to distribution and finally sale to the consumer. Value may also be created from sales of gas from an integrated LNG project vehicle into the local domestic market."

- "In any case, such attempts to segment the risk and value drivers of different parts of the integrated LNG chain is conceptually flawed. Each element of an integrated LNG value chain is wholly interdependent - from the upstream wellhead to the LNG delivery point (be this FOB or DES). From a project perspective, gas would not be developed without the export infrastructure to process and sell it. Conversely this infrastructure would not be built without the development of the project vehicle's ringfenced gas.

  This point is underlined by the fact that integrated LNG projects are sanctioned as a whole, and final investment decisions (FID) are binary. This essentially confirms all risks and rewards are shared equally across the entire project vehicle from a project sponsor's perspective."

The Industry Today and the 50/50 Split

- "Profit allocation between upstream and downstream is a function of the balance of bargaining power between the two phases. The allocation of variations in gains and losses between the two parties reflects the ability that each counterparty has to either capture the gains for itself or push the losses to the other side.

Numerous soft elements determine this supplier/buyer bargaining power. These include; the relative supplier/ buyer concentration, the buyer's switching costs, the ease of vertical integration for either the buyer or supplier, the sensitivity to price of the buyer, the product differentiation of the supplier and the availability and cost of substitutes. The interplay and conversion of these qualitative elements into quantitative percentage splits is a judgement call and very difficult to do with any degree of rigour or consistency."

- "…. the way LNG price is derived at the point of sale remains very similar and therefore offers us no additional insight into deriving proxy prices at the upstream ringfence. Likewise, while the absolute price of LNG and its value as a commodity is significantly higher now than in 1998, this consideration remains indifferent to the value allocation discussion.

  Capital and operational costs have increased substantially both for upstream gas and downstream LNG. But again, it is unclear how the evolution of these cost patterns has diverged in terms of value allocation between upstream and downstream over the period and the implications this might have for the 50:50 split. During the last wave of Australian LNG build, plant costs on a per tonne basis ended up among the highest ever seen in the history of the industry due to cyclical cost inflationary pressures. These impacted the value and risk proposition of the downstream and called into question traditional perceptions over upstream and downstream project risks and where value is generated."

- "But as the example of cost escalation in the last wave of Australian LNG shows, the external environment is variable, difficult to forecast and ultimately shifts value perceptions back and forth between upstream and downstream over any projected period. Australia high cost labor, often geographical remoteness of its infrastructure and extreme weather-related events will continue to impact the risk profile of future and existing downstream. And underutilised LNG capacity (both currently and threatened in the future) increase downstream unit costs. "

  As in 1998, the vast majority of Australia's upstream gas resources would not be developed without the infrastructure and market opportunity that LNG provides. The value-creating activities downstream (liquefaction, marketing and shipping of LNG) similarly require the development of upstream feed gas. This symbiotic relationship remains strong and presents little evidence for change on a circumstantial basis."

The conclusions drawn in the assessment undertaken by Wood Mackenzie suggest a decision to arbitrarily differentiate value creation between the upstream and downstream is fundamentally challenged as integrated projects are developed as an interdependent whole. How much value sits within each ringfence is a judgement call and subject to variations over time. The RPM and its profit split methodology (a 50/50 ratio) constituted a workable solution to calculating proxy transfer prices in line with the PRRT legislation.

3.2 Treatment of 'Excluded' Costs

> *These costs are excluded because they are not incurred in the processing or production of project product and therefore should not be included in the netback and cost-plus formulas to calculate the price for the project sales gas. However, most of these costs remain eligible for deduction under the Act. The exclusion of such costs prevents them from both reducing assessable receipts and increasing deductible expenditure.*
>
> 2005 PRRT Regulations Explanatory Statement, p.26

Regulation 27 of the Petroleum Resource Rent Tax Assessment Regulations 2005 excludes certain costs from the RPM calculation. Excluded costs are:

- exploration cost under section 37 of the PRRT Act;
- costs incurred in carrying out any feasibility or environmental study prior to the production of project sales gas;
- costs incurred in removing infrastructure facilities used for the integrated GTL operation;
- environment and site restoration costs; and
- expenditures listed under paragraphs 44(a) to (h) of the PRRT Act

The Consultation Paper raises a question about the possible asymmetric treatment of certain costs. APPEA is not aware of any such situations, however it is noteworthy that the Arthur Andersen report specifically addressed the question of the appropriateness of excluding certain categories of costs in the price determination process.

Arthur Andersen indicated that certain cost should be excluded from the operation of the RPM, with two key cost categories being exploration and closing down/abandonment expenditures. These costs, together with a number of others, are not incurred in the processing or production of feedstock gas and therefore it was considered not appropriate for them to be included in the RPM calculation.

These costs are excluded as they are costs which would not and should not influence the price at which such gas would be transacted between related parties. In particular, the amount incurred in exploring for and discovering a resource has no bearing on the price at which such gas may ultimately be sold, wither as LNG or as feedstock gas. The RPM methodology rather consider the costs and risks of the upstream recovery of natural gas (once identified) and processing into sales gas, and the downstream processing of sale gas to project liquid. This approach also ensures the outcome of the RPM is indifferent to whether gas is discovered as part of an integrated project or purchased from another project, and then processed by the project facilities.

3.2.1 Exploration Costs

Decisions made to explore for gas resources of the scale typically encountered in areas offshore north-west Australia are often made on the basis of a desire to identify quantities of gas to service export markets. Exploration decisions are generally not made with a view to solely suppling natural gas to domestic markets. The sheer scale of the cost of commercialising discoveries necessitates production of a size that can only be achieved through export sales. Without the ability to liquefy gas for export purposes, significant amounts of past exploration expenditure previously committed would not have been spent.

To arbitrarily allocate exploration expenditure (whether wholly or in part) on an unspecified basis to the upstream and downstream phases of a project would represent a flawed allocation process that would fail to understand the factors driving exploration decisions.

In the event a decision was made to allocate exploration costs to the different phases of an integrated project, a number of potentially complex questions would need to first be addressed. By way of example:

1. Should successful and unsuccessful exploration costs be treated separately, noting that the majority of exploration undertaken in offshore areas does not lead to either the discovery of hydrocarbons or the development of commercially recoverable petroleum resources?
2. In the context of question 1, what would constitute successful exploration?
3. Should exploration costs be treated as capital costs or operating costs in the RPM? Different treatments would arguably need to apply to successful and unsuccessful exploration.
4. How should costs be allocated within the RPM when a product other than feedstock gas is produced within a project?
5. What percentage of exploration costs should be attributed to the different phases of a project, and on what basis would/could costs be allocated?
6. How should project feasibility costs be treated?

3.2.1 Abandonment/Decommissioning Costs

Abandonment costs were not included in the RPM calculation. The final costs would have no impact on the gas transfer price since no gas is likely to be produced at the time costs are incurred.

A number of the complexities outlined above with respect to the treatment of exploration costs would also exist for the treatment of abandonment costs (for example, where multiple products are being produced and where an allocation would need to be made between upstream and downstream). In addition, if a decision was made to 'notionally' bring forward such costs for the purposes of the calculation of the RPM, a decision would need to be made about both the quantum of the costs and over what period the costs would be allocated.

Overall, APPEA can see no case for a change to the existing treatment of excluded costs. These costs were purposefully excluded in the design of the methodology. In the event a different treatment was to be considered, a number of potentially complex allocation issues would need to be addressed that would add a layer of subjectivity and complexity on what is presently a relatively transparent and well understood process.

3.3 Cost Plus/Netback Interaction

The Arthur Andersen report discussed in some detail a situation where the netback price and cost plus price effectively 'overlap'. It was noted that this can occur for a number of reasons, however it will most likely occur early in the life of a project, where low production volumes exist at a time where there are relatively high production costs (particularly depreciation).

A number of different approaches were considered to address this situation. One early proposal from the Government envisaged the application of a floor price set at a level of 50% of the price at the point where the estimated netback price equals the estimated cost plus price.

Following further consideration by the Department of Industry, Science and Resources during 1999, a modified approach was considered that sought to factor in a volume coefficient to create a nexus between the cost base and the level of production. During this time, it was also proposed by the Department that in instances where the cost plus and netback calculations crossed over, the netback price should prevail.

This treatment was subsequently confirmed in an ATO discussion paper provided to industry in 2000, where it was stated that "*If the cost plus price is higher than the netback price (a notional economic loss situation for the project), then the MPC price will be equal to the netback price.*" This treatment was contained in a draft of the regulation provided to industry by the ATO in 2002. It became a common feature in subsequent drafts and the final regulation.

In 2008, the ATO released a taxation ruling (TR 2008/10: Petroleum resource rent tax: application of Petroleum Resource Rent Tax Assessment Regulations 2005 to an integrated gas-to-liquid operation). In that ruling, the following comment was made in relation to circumstances where the cost plus and netback prices intersected:

> *"However, where the overall integrated GTL operation incurs an economic loss because the upstream and downstream costs can't be covered (in other words, where the netback price is lower than the cost-plus price), the entire loss is attributed to the upstream stage and diminishes the assessable receipts for the sales gas (the RPM price is taken to be the netback price). That is, the liability of the taxpayer to pay PRRT is reduced/eliminated so far as the operation incurs an economic loss (Regulation Impact Statement to the Explanatory Statement)."*
>
> ATO TR2008/10, p.4

The final treatment adopted within the methodology remains appropriate. Importantly, it avoids the creation of a notionally 'profitable' project by creating an artificially high price purely for PRRT purposes. As such, APPEA recommends the retention of the existing provision.

3.4 Treatment of Other Commodities - Joint Costs

> *If the issue of common costs arises in a cost plus calculation for a project producing other products in addition to gas, it is appropriate to differentiate the total capital and operating expenditures incurred if the project was producing gas alone (that is unavoidable costs) from expenditures which can be directly attributed to other products (avoidable costs).*
>
> Arthur Andersen Report, p.18

A mechanism exists within the RPM to address situations where cost centres are used within projects to process multiple products. To develop a gas transfer price, only expenditures that are directly related to the integrated gas to liquids process should be included in the calculation. Where more than one product is produced or processed within a cost centre (or it has more than one use), the relevant cost needs to be apportioned.

The Explanatory Statement covering the introduction of the 2005 regulation outlines the treatment as follows:

> *"The Regulations provide for the integrated GTL operation to be divided into phases by the phase points. Phase points are required to allow for the accurate apportionment of phase costs where multiple use of a phase occurs. Only those costs that relate to the production and processing of project sales gas into project liquid are included in the RPM for the*

determination of a gas transfer price. Regulation 7 further describes when multiple use occurs.

Costs of the operation are attributed to the various phases of the operation and the direct costs are apportioned between project product and other petroleum product of the operation using an energy coefficient appropriate for the phase (see Regulation 32 which attributes costs to each phase and Regulation 37 which applies the energy coefficient to the direct costs only)."

Select Legislative Instrument 2005 No. 329 (Explanatory Statement), p.8

This treatment of joint costs within the RPM model was discussed at length within the Arthur Andersen report, and was the subject of considerable attention at the time the mechanics of the regime were being developed by the Government. One concern identified was the treatment of costs acquired or commissioned within a year, however the subsequent consultation process identified an effective approach to address this and all other related matters.

The present provisions are equitable, efficient and sustainable for the long term operation of the RPM, and should be retained.

3.5 Capital Allowances

As the residual price method recognises the integrated nature of the risk-reward relationship between upstream and downstream LNG processes, it is feasible to use an integrated project WACC. Clearly this single rate of return can be applied equally to both upstream and downstream costs, thus the netback and cost plus equations will utilise the same WACC rate.

Arthur Andersen Report, p.48

The capital allowance is the rate applicable under the RPM to reflect the return necessary to underpin an investment within an integrated gas to liquids project. As the RPM is designed to address the integrated nature of such projects, a single rate is used across the entire project. It is intended to provide a return which is reflective of the conditions in relevant markets and the risk involved in the project.

The Arthur Anderson 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 report noted that "*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*".

It was also noted by Arthur Andersen that one of the advantages of the recommended model was that it "*….avoids the explicit pre-determination of rents to upstream and downstream LNG processes*."

The Explanatory Statement accompanying the introduction of the PRRT Regulation in 2005 (Select Legislation Instrument 2005 No.239) addressed this issue in terms of the rate and its application across an entire project.

> *"The capital allowance is relevant to the RPM for both the augmentation and reduction of capital and the allocation of capital. This definitional regulation sets out how the capital allowance is to be computed.*
>
> *The capital allowance provides a rate of return on the capital employed in an integrated GTL project, whether to the upstream or downstream stages of the project or both.* ***As the RPM recognises the integrated nature of the risk-reward relationship between upstream and downstream GTL processes, a single overall project capital allowance is used for both the netback and cost plus calculations****. The capital allowance is equal to the long-term bond rate plus 7 percentage points. This capital allowance represents a proxy for the cost of equity.*
>
> *The capital allowance to be applied to capital costs is adjusted each year to account for the changing risk-free rate of return (assumed to be the long-term bond rate as defined in the Act). The capital allowance for the relevant year only applies to capital costs incurred in that year and is used to allocate costs to that and subsequent years of tax for the remaining expected operating life of the unit of property. Once determined the annual capital allocation for a capital cost does not change (except to reflect changes to the expected operating life of a unit of property, in which case the allocation changes for the year in which the operating life changed and subsequent years under paragraph 36(5)(a))."* (Emphasis added)
>
> Explanatory Statement 2015 p.14

As noted in the Arthur Andersen Report, "*….the residual price methodology recognises the integrated risks of an LNG project via use of a single WACC rate for both upstream and downstream activities. This single WACC rate will reflect an integrated LNG project's risk-return profile*." In terms of the modelling undertaken in Report, it was noted that the results were not overly sensitive to changes in the WACC rate, reflecting the integrated nature of the operation.

The Callaghan Report discussed aspects of the capital allowance rate, noting there are a range of variables that will impact on the cost of capital.

> *"The actual cost of capital for each integrated LNG project will vary between projects and the participants in each project. It is also reasonable to assume that in many projects the actual capital funding mix will include a mix of debt and equity."*

It was also noted that:

> *"The other risk is that by not providing a sufficient capital allowance the operation would be in notional loss for economic purposes but this would not be recognised under the RPM. The result in this case is that the notional loss would not be attributed to the upstream, contrary to the original intent of the RPM."*
>
> Callaghan Report, p.161

Careful consideration was given to the design of the RPM and in particular, the treatment of capital within the model. APPEA is not aware of any material changes that have occurred since the regime's introduction that would warrant any variations to the existing treatment.

Section 4: Other Issues

This Section of the submission covers a number of aspects of both the RPM and the PRRT regime, including the scope of the tax and its applicability to potentially new commercial structures.

4.1 Date of Effect and Impact of New Provisions

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."

Arthur Andersen Report (p.35)

Effective Date

It is critical that any material changes to the GTP regulations are carefully considered and if proposed are applied on a prospective basis, that is to new projects which apply for a Production Licence (PL) from a date after the conclusion of the review. This principle of prospectivity is consistent with the Callaghan Report recommendations.

APPEA considers that any changes resulting from the GTP review are separate from the already enacted changes and should be subject to their own date of effect after any GTP changes are enacted. This is especially the case given the GTP review and consultation will be ongoing at this time and the final recommendations will not be known for some time.

Ensuring any changes are prospective in nature will prevent creating investment uncertainty for industry proponents who may be considering final investment decisions on new projects prior to completion of the review process.

Protecting Combination Certificates

In the LNG industry it is common to have investment decisions made and infrastructure built with the intention to progressively develop Production Licenses and Retention Leases held at the time of making the investment decision. It is essential that any GTP changes recognise the lifecycle of long-term, multi-field LNG projects and how these projects are sanctioned for development.

Any GTP changes should not taint projects sanctioned prior to the effective date of the changes by subjecting them to new provisions if these projects are combined with PLs issued after the effective date for the changes. APPEA is concerned that if this is the case, PRRT project combinations would no longer be feasible, causing a series of administrative, practical and tax technical issues and complexities.

If PRRT project combinations become infeasible, the calculation of PRRT revenue would be extremely complex and virtually unworkable, defeating the purpose of project combinations in the first place. Examples of administrative and practical tax issues are as follows:

- Production from each individual field will need to be tracked separately;
- Singular sales invoice will need to be split by PRRT project. As sales contracts do not exist for individual fields, the split of revenue between PRRT projects could be based on an arbitrary

method and depending on the PRRT profile of each individual taxpayer, split methodologies may even be different for each joint venture partner;
- Capital and operating costs would require allocation to individual fields, which is contrary to operational reality;
- Significant increase and duplication of work for taxpayers and ATO due to the increase in uncertainty in tax lodgement positions due to the additional complexities;
- Taxpayers IT systems will need to be redeveloped, significantly increasing the cost of compliance.

In terms of application of any changes APPEA recommends:
a) any proposed GTP changes should apply prospectively (i.e. to PLs granted following completion of the review) such that there should be no impact to existing PLs or PLs granted prior to completion of the review; and
b) to the extent any PLs granted in respect of RLs held at the time of an original FID and subsequently added to a PRRT combination certificate (which existed prior to the GTP changes) in relation to the original FID PLs, are not impacted by any proposed GTP changes.

APPEA requests that Treasury further consults in this area to ensure that a significant barrier does not exist for the combination of projects in circumstances where they are economically and operationally one project.

4.2 Industry Developments and Tolling Arrangements

LNG development in Australia in the short and medium-term future is likely to involve maximising use of existing infrastructure. This includes toll processing of currently undeveloped offshore resources through existing infrastructure and in some cases, expansion of these existing facilities.

No new Australian greenfield LNG projects have been announced in recent years or are currently proposed. This contrasts with several jurisdictions, including the United States, Qatar, and Mozambique, where a number of greenfield LNG developments have recently or are soon expected to take final investment decisions.

As noted in the Consultation Paper, it is important to ensure the GTP regulations continue to be fit for purpose and compatible with the commercial arrangements underpinning future Australian LNG developments, including LNG tolling and other processing arrangements. It is also important the GTP arrangements do not place these projects at a competitive disadvantage to our foreign competitors.

It is clear the multiple use of infrastructure which may occur as a result of tolling and other processing arrangements was considered in the original design of RPM. This is evidenced by comments and examples in the 2005 Explanatory Statement and the inclusion of mechanics in the regulations to take such multiple use into account:

> *The Regulations also recognise that an integrated GTL operation may be used to process gas from more than one petroleum project, and may produce other products as well as project liquid. When this occurs, the Regulations allow for the capital costs associated with those parts of the operation used to process gas of more than one petroleum project or produce more than one product to be apportioned. This means that the RPM price only reflects the share of the costs associated with producing project liquid from project natural gas.*

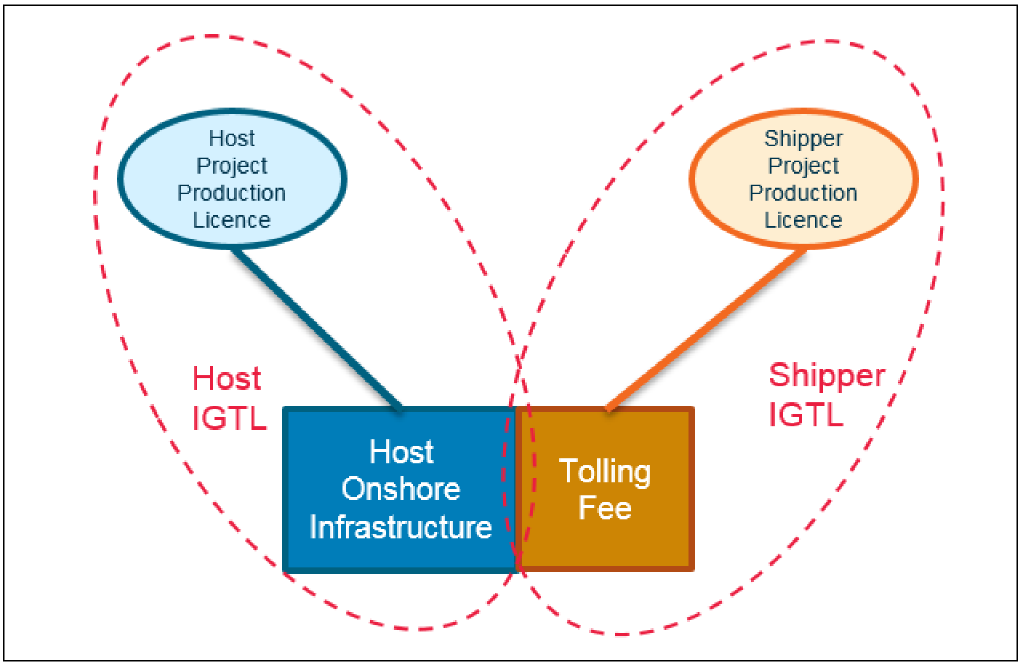
.....
A feature of an integrated GTL operation is that there is generally common ownership of the operation which recovers the gas, converts it to sales gas and processes the sales gas into a liquefied product for sale. However, there may be other ownership interests in different parts of the operation, or the facilities may be used for the processing and production of petroleum product other than project product. The Regulations allow for differing ownership interests across the integrated GTL operation should these exist.

The RPM in its current form largely works well where there is expanded use of existing infrastructure and support its continued application. In particular, as outlined at 4.2.1 below, the mechanisms of the RPM already operate appropriately in the context of tolling arrangements but would benefit from clarification on certain points. In respect of arrangements where existing infrastructure is used to process gas from expansion fields with common owners, there are some difficulties in the technical application of the RPM where no toll payment exists, as outlined in 4.2.2.

4.2.1 Application of Existing Regulations to Tolling Projects

While processing arrangements may take a variety of forms, the following discussion provides an outline of the operation of the existing PRRT legislation and RPM mechanics to a tolling arrangement with the following features:

- An existing integrated LNG project with onshore processing infrastructure (hereafter referred to as 'Host Project') is expected to have sufficient excess capacity to provide shore-based gas transportation and processing services to other resource owners while at the same time continuing to produce and process gas from its own petroleum titles;
- Another resource owner (hereafter referred to as 'Shipper Project') owns a different petroleum title to the Host Project (no combination certificate exists between the two). The Shipper Project only has upstream (gas extraction) infrastructure. Thus, the Shipper Project extracts this petroleum (equity gas) using their own upstream infrastructure which ties into the Host Project's shore-based infrastructure (typically upstream of the liquefaction point) and pays a fee (toll) to the Host Project for the transportation and processing of their gas into LNG;
- The Shipper Project owner retains title to their equity gas throughout the process (including fuel/flare gas), notwithstanding the gas is commingled with Host Project gas. The Shipper Project owners lift their entitlement (based on the proportion of feedstock gas delivered at the tie-in point) as LNG at the Host Project offtake facilities (LNG loading jetty). The Host Project has custody of Shipper Project gas for processing purposes (under a legal bailment arrangement) but at no stage takes legal title to the gas.



It is acknowledged some processing arrangements will involve different or more complex circumstances to the above and may have separate PRRT considerations, however these facts provide a useful starting basis in reviewing the application of the existing framework principles to a typical tolling arrangement from both a Host Project and Shipper Project perspective.

4.2.1.1 Host Project perspective

Multiple Use of Infrastructure

The use by the Host Project of its existing infrastructure for the dual purpose of processing its own gas, together with processing Shipper Project gas, is contemplated in the existing regulations and referred to as the 'multiple use' of infrastructure.

This is within the scope of the stages within an 'integrated GTL operation' as outlined in section 8 of the Regulations and as specifically contemplated in the definition of 'multiple use' in section 10:

> *(2) A reference to the* ***multiple use*** *of a phase relating to the production of project sales gas is a reference to the use of the unit of property, at any time during the operating life of the integrated operation, to produce marketable petroleum commodities other than project sales gas from petroleum (whether or not the petroleum was recovered from the petroleum project of the operation).*
>
> *Example 1: Plant is used to produce sales gas, some of which is to be sold for direct consumption as energy.*
>
> *Example 2: Plant is used to produce sales gas from natural gas recovered outside the operation.*

[underlined emphasis added]

Where multiple use of a phase of an operation occurs due to introducing and processing gas recovered outside the operation the following sections have natural effect to adjust the RPM calculation of the Host Project:

- Section 9 (Phase points of integrated operation) – As stated in example 2 to this section, the introduction of natural gas from a source outside the Host Project integrated GTL operation will result in the creation of at least one new phase point of the operation due to change in ratio of project product to total product flowing through the operation before and after the tie-in point.
- Section 43 (Applying energy coefficients to costs of each phase) - Provides an appropriate mechanism to account for the multiple use by apportioning the amount of the Host Project capital and operating costs included in its RPM calculation for the relevant year based on the energy ratio of its own gas from its PRRT project (phase project energy) versus Shipper Project owned gas entering the phase in that year.

Example 3 of the Explanatory Statement of the 2005 Regulations provides further indication that the application of the RPM and the above mechanisms to third party tolling arrangements was specifically considered at the time of implementation:

> ***Example 3: Calculation of RPM price – multiple phases in the upstream and multiple use in two phases (one upstream and one downstream)***
>
> *Ausgas Pty Ltd is developing an integrated GTL operation which sources natural gas from 2 gas fields. It wholly owns Gas Field 1 and the upstream and downstream stages of the integrated GTL operation. Gas Field 2 is not owned by Ausgas Pty Ltd. Ausgas will process Gas Field 2 gas into liquid on a 'tolling' basis, receiving assessable receipts for this service (while the Gas Field 1 production licence continues). Its PRRT will be worked out by claiming its deductible expenditures in full against the combined total of its receipts from the sale of project liquid and its tolling operations. The downstream stage processes sales gas from both gas fields.*
>
> *In order to comply with subregulation 6(3), Ausgas Pty Ltd is required to notify the Commissioner that the upstream stage is divided into 2 phases:*
>
> - *Phase 1 of the upstream stage includes the facilities to extract and transport natural gas from the Gas Field 1 (the gas field for which the RPM price in this example is being calculated) up to the phase point.*
> - *Phase 2 commences at the phase point where natural gas from Gas Field 2 (a petroleum project not owned by Ausgas Pty Ltd) enters the integrated GTL operation and is transported and processed into sales gas for processing in the downstream stage. The facilities in phase 2 are also used to process gas from Gas Field 1 (project sales gas).*
>
> *The downstream stage is treated as one phase. The downstream facilities are used to process sales gas from Gas Field 1 and Gas Field 2.*

The RPM outcome of this Example in the Explanatory Statement is a reduction in costs (through the energy coefficient mechanism) included in upstream phase 2 and the downstream phase of the Ausgas integrated GTL operation due to the multiple use of these phases to process petroleum from Gas Field 2. This reflects that the capital and operating costs for these phases of the project are no longer fully attributable to the production of Ausgas LNG.

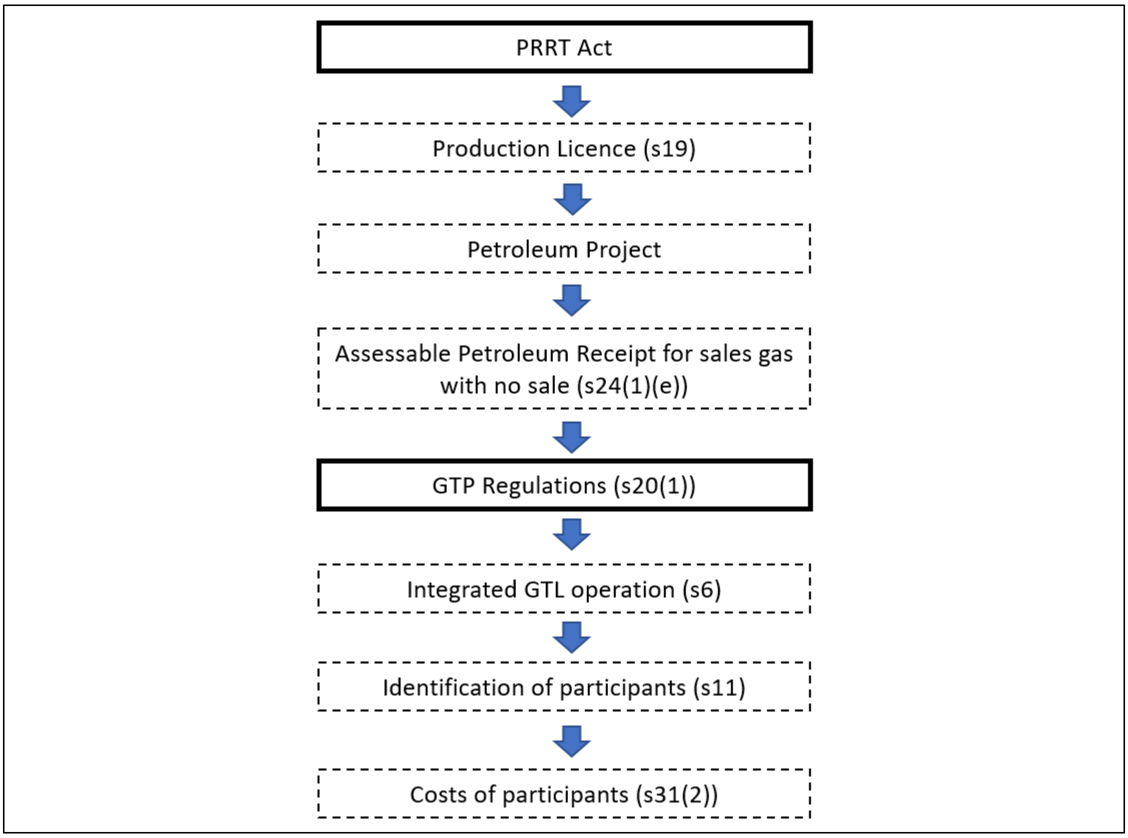
This apportionment mechanism for multiple use of the infrastructure results in an increase in the netback price component for the Host Project RPM to the extent the processing services are referable to operations downstream of the PRRT ringfence and a decrease in the cost-plus price component of the RPM to the extent the transportation/processing services are within the upstream stage.

Separately, the income (toll) derived from the provision of the processing services is not relevant to the calculation of the Host Project RPM price, but is brought to account as assessable tolling receipts under paragraph 23(1)(aa) and section 24A of the PRRT Act (to the extent it is attributable to services provided upstream of the PRRT ringfence).

The above mechanisms provide an appropriate means to deal with multiple use of the infrastructure from the Host Project perspective and remain suitable for future tolling arrangements where ownership of gas remains with the respective upstream parties throughout the process.

<u>4.2.1.2 Shipper Project perspective</u>

In considering the application of the GTP regulations from the Shipper Project perspective it is necessary to follow the link between the identification of a petroleum project under the PRRT Act and the relevant integrated GTL operation (and participants of such) in the regulations.



Identification of relevant project and integrated GTL operation

PRRT as a project-based tax applies separately to each petroleum project by reference to the production licence in force for that project (or combination certificate) as per Section 19 of the PRRT Act. The identification and calculation of the assessable petroleum receipts (including assessable receipts calculated using the gas transfer price) of a PRRT taxpayer is therefore determined by reference to the petroleum project (i.e. production licence) interest held by the taxpayer.

For a party with an interest in a Shipper Project production licence which obtains LNG processing services from another party, with no sale of gas between the parties, paragraph 24(1)(e) of the Act provides for the taxpayer's assessable petroleum receipts for the petroleum project to be worked out in accordance with the Regulations (and the taxpayer is also the taxpayer for the purposes of the Regulations – see section 5 of the Regulations):

> ***"24 Assessable petroleum receipts***
>
> *(1) For the purposes of this Act, a reference to assessable petroleum receipts derived by a person in relation to a petroleum project is a reference to:*
>
> *:*
>
> *(e) where the regulations apply to any sales gas produced from petroleum from the project, and that sales gas becomes or became an excluded commodity otherwise than by virtue of being:*
>
> *(i) sold; or*
>
> *(ii) treated or processed, or moved, for re-injection or destruction or for use in carrying on or providing operations, facilities or other things of a kind referred to in section 37, 38 or 39 in relation to the petroleum project;*
>
> *the amount worked out in accordance with the regulations;"*

That is, the relevant petroleum project for which the assessable petroleum receipts are to be calculated, including by the operation of the Regulations, is that of the Shipper Project. For this purpose, paragraph 20(1) of the Regulations then links the operation of the Regulations and the determination of assessable petroleum receipts under paragraph 24(1)(e) to whether the sales gas is project sales gas of an integrated GTL operation.

Identifying the petroleum project is also the starting point for the identification of the relevant integrated GTL operation under section 6 of the Regulations:

> ***"6 When an integrated GTL operation exists***
>
> *(1) An **integrated GTL operation** exists if there is an operation (the overall operation) in which:*
>
> *(a) petroleum is, or will be, recovered from a petroleum project; and*
>
> *(b) sales gas is, or will be, produced from some or all of the petroleum; and*
>
> *(c) some or all of the sales gas is, or will be, processed into a liquefied product."*

Based on the definition above, in order for there to be an integrated GTL operation, there needs to be an operation that consists of the recovery of petroleum from a petroleum project, from which sales gas is produced and liquefied. The identity of the petroleum project is the fulcrum on which the corresponding integrated GTL operation is constructed and is pivotal to the identification of what is project natural gas, project sales gas and project product of that integrated GTL operation for application of the Regulations (noting the intent of the RPM provisions is that the RPM should only reflect costs associated with *project product* (Explanatory Statement to the 2015 Regulation, page 7)).

It is important to note therefore that a distinct integrated GTL operation is to be identified on the basis of a particular petroleum project; the definition of an integrated GTL operation does not encompass the aggregation of multiple petroleum projects but rather requires consideration on a separate petroleum project basis (i.e. there is one integrated GTL operation for one petroleum project). Otherwise, if an integrated GTL operation were to include the collection of separate petroleum projects, there could never be petroleum sourced from outside such an all-encompassing operation, which would be contrary to what is plainly envisaged by the structure and wording of the Regulations (concerning multiple use and energy coefficient) as outlined above.

The definition of an integrated GTL operation that is predicated on a single petroleum project is flexible and precise enough to ensure that an upstream project utilising a third party's downstream infrastructure for gas tolling or processing is able to identify a relevant integrated GTL operation for which a unique RPM price is calculated for the sales gas of that project exclusively (having regard to its own upstream profile and the fact that it has its gas liquefied via a tolling arrangement), separate to another integrated GTL operation that yields a different unique RPM price for the sales gas of that other petroleum project. This approach to defining an integrated GTL operation remains suitable to cover a range of commercial arrangements.

In summary, for a tolling arrangement as outlined involving a Shipper Project procuring LNG processing services from a Host Project, we consider the following outcome would arise:

- There is one integrated GTL operation comprising the recovery, processing and liquefaction of gas from the Host Project; and
- There is a separate integrated GTL operation comprising the recovery of gas from the Shipper Project and the processing and liquefaction of that gas through the Host Project's shore-based infrastructure.

This outcome for the Shipper Project integrated GTL operation is also consistent with the comments in the 2005 Explanatory Statement which provide:

> *The Regulations allow for differing ownership interests across the integrated GTL operation should these exist.*

Identification of participants of the integrated GTL operation

The identification of the participants of an integrated GTL operation is integral to the calculation of the RPM price for each taxpayer in the operation. Costs incurred by participants in an integrated GTL operation are included in the calculation for that operation while payments between participants in the same integrated GTL operation are excluded.

Currently, section 11 of the Regulations provides:

> *A person is a participant in an integrated operation if the person holds an interest in the operation that entitles the person to petroleum product or electricity of the operation at the end of at least one phase.*

For the Shipper Project integrated GTL operation where the taxpayers retain legal title to their equity gas throughout the process (including where used for fuel/flare purposes), section 11 indicates that the Host Project owner should not be regarded as a participant in the Shipper Project integrated GTL operation. Likewise, the Shipper Project owner should not be a participant in the Host Project integrated GTL operation.

The technical outcome in this scenario is also an important practical outcome for the following reasons:

- As they are not participants in the Shipper Project integrated GTL operation, the Host Project owner is not required to share potentially commercially sensitive information regarding their underlying capital and operating cost structure with their customer (the Shipper Project). In many cases and depending on the Host Project circumstances, sharing of such information may also otherwise be practically impossible or not available in a form that would be required for the Shipper Project calculation.

- The Shipper Project owner is able to determine their RPM price by reference to their own cost structure (including toll paid to Host Project) and realised LNG prices. In this way, the gas transfer pricing outcome for a Shipper Project is not influenced by the cost structure of a 3rd party service provider (which may or may not be an oil and gas company or PRRT taxpayer). This outcome also respects the commercial arrangement entered into and payments made between the parties. Similarly for the Host Project owner, its gas transfer pricing outcome should not be influenced by the Shipper Project's upstream costs, and there will be appropriate apportionment for multiple use of some of Host Project's shore-based infrastructure to account for the processing of non-Host Project gas that is sourced from Shipper Project.

This outcome for the Shipper Project is consistent with the illustration in Example 3 of the 2005 Explanatory Statement. In the same way that the costs of Gas Field 2 project in Example 3 were not included in the Ausgas project RPM calculation, we expect that had this example been expanded, provided the Gas Field 2 project owners maintained title to Gas Field 2 product at all time during processing by Ausgas, the underlying capital costs of Ausgas project would not have been included in the Gas Field 2 RPM calculation.

Notwithstanding the above outcome, a Shipper Project may still require certain information from a Host Project to calculate the RPM price for its integrated GTL operation, for example:

- Details as to a reasonable apportionment of the toll between the upstream and downstream stages of the operation. In this regard, the Host Project would also likely need to identify the upstream portion of the toll in any event for the purposes of calculating its assessable tolling receipts and deductible expenditure.
- Quantity of project sales gas of the Shipper Project at the taxing point.

This information should be non-sensitive in nature and likely be able to be dealt with through contractual terms between the parties for supply of information.

We note although the above technical outcome for Shipper Project can be interpreted from the existing Regulation, industry would welcome further comments to clarify this as a policy position to provide additional certainty for tolling projects going forward. For example, through additional comments or expanded examples in the Explanatory Statement to the Regulations. We would be happy to work with Treasury to provide practical examples in this regard.

4.2.1.3 Recommendations for Tolling Projects

Identification of Participants

While the definition of participants in section 11 of the Regulations may be suitable in many scenarios, scope exists to clarify this section having regard to the nature of future developments, including 3rd party processing and hub tolling arrangements.

The 'entitlement' of a person (which we understand to refer to legal title, as opposed to custody or bailee arrangements) to petroleum product of an operation (which determines whether they are a participant in that operation) may not be the sole or best indicator of the degree of commercial and operational interrelatedness between entities that own different parts of the integrated GTL value chain (and the corresponding ability to acquire or procure the visibility of underlying cost information), or whether participants in one should be considered participants in the other.

The need for clarity in the definition of participants is even more apparent in more complicated arrangements which may involve Shipper Projects obtaining transport or processing services from multiple entities as part of the production chain, or in hub arrangements involving multiple Shippers Projects obtaining processing services from a single Host Project. The ability to maintain a clear delineation between the participants of each project in these situations is key to ensuring the RPM is capable of being applied for each project independently with regard to the actual costs incurred and LNG revenues derived by each project. This is as opposed to situations of having to share cost information between unrelated parties which is not only likely to be commercial and practically difficult but may also give rise to anomalous outcomes.

Simplified identification of phases for Shipper Projects

Section 9 of the Regulations currently provides that a phase point of an integrated operation arises at “any point in the flow of project product through the operation at which there is expected to be a difference in the ratio of project product to total product flowing through the operation before and after the point.”

This currently presents some practical difficulty for a Shipper Project paying a toll to a Host Project as the identification of phase points for the Shipper Project integrated GTL operation would require intimate knowledge of the Host Project process flows. This is notwithstanding that the Shipper Project may ultimately be paying a service fee for a given quantity of LNG (and potentially other marketable petroleum commodities) processed through the Host Project facilities and is not otherwise concerned with the precise flows throughout these facilities provided the expected processing quantities are achieved.

> *Example – Shipper sends gas to Host Project for processing and pays a toll fee per unit of gas processed into LNG and a separate toll fee per unit of gas processed into domestic gas. Within the Host Project facility, there may be various separation points or recycle streams related to the production of LNG and domestic gas for both the Shipper Project and the Host Project. Technically each of these physical separation points or recycle streams may create a phase point for the Shipper Project integrated GTL operation, notwithstanding the Shipper Project is primarily concerned with the output from the facilities and not the process flows within the facilities.*

Options should be explored to simplify the identification of phase points for toll paying parties in these circumstances. One option for this simplification could focus on treating each toll segment (including upstream and downstream segments of such) as a separate phase of the Shipper Project, without the need for the Shipper Project to have information as to changes in underlying process flows occurring through the underlying infrastructure related to that toll segment. The energy coefficient for such phases could be determined by the energy ratio of the Shipper’s Project’s product processed and for which the toll payment relates. For example:

- A toll payment for LNG processing may have both an upstream and downstream phase, for which an energy coefficient of 1.0 should be applied to both phases given the payment is wholly attributable to the production of the Shipper’s project sales gas / LNG;
- A toll payment for domestic gas processing should have an energy coefficient of zero applied, given it is wholly attributable to the production of a separate marketable petroleum commodity that is not project sales gas / LNG;

- A toll payment covering both LNG and domestic gas processing should have an energy coefficient applied which is determined based on the relative energy ratio of Shipper's gas that will be processed into LNG versus Shipper's gas that will be processed into domestic gas as part of the service covered by the toll payment.

Cases where participants are entitled to gas of another project

There may be cases where participants in a project do have entitlement to gas of another project (and are therefore 'participants' as defined), notwithstanding that the entitlement is minor or incidental to the overall operation.

In these situations, it would make sense to allow each participant to elect an RPM approach consistent with the above example (i.e. by including payments to the toll service provider in its RPM instead of needing to look through to the underlying costs of the toll service provider because it is considered a participant). This is particularly important in circumstances where the projects involve unrelated parties and commercial tensions exist to limit the capacity or willingness to share confidential cost information.

In the absence of such a choice/election being available, there is a need for further legislative or administrative measures to overcome the difficulties in willingness and capability to share sensitive information between parties.

4.2.2 Application of Regulations to Projects with Common Owners and No Tolling Fee

Ensuring the regulations are fit for purpose for future developments involving other commercial arrangements for sharing or use of infrastructure will require further consideration. For example, technical uncertainties will arise in circumstances where no tolling fee is paid between common owners of two or more integrated GTL operations using the same facilities to process gas. As an example:

- An existing combined PRRT project with onshore LNG processing infrastructure (hereafter referred to as "Original Project") produces and processes gas from its petroleum titles. The Original Project was sanctioned to commence production in multiple stages with multiple PLs being granted over time (pre and post July 2019). The onshore LNG processing infrastructure was developed on the basis that it will process gas from the Original Project PLs and subsequent PLs over the life of the project. Four Joint Venture Partners (JVPs) hold an interest in the Original Project's PLs and associated processing infrastructure.
- A subsequent PL was granted (hereafter referred to as "Extension Project") and the JVPs decided not to apply for the Extension Project to join the Original Project's combination certificate. The Extension Project is owned by the same 4 JVPs that own the Original Project. The Extension Project processes its gas using the onshore processing infrastructure of the Original Project. No tolling fee is paid by the Extension Project to the Original Project as they are same persons and are commercially, economically and operationally viewed as one project.

Based on the current regulations, Original Project and Extension Project would be considered two separate integrated GTL operations. The Extension Project has no mechanism for recognising the costs that would be attributable to the project, however, the Original Projects costs will be reduced due to the processing of non-project product. This results in an asymmetric system and does not achieve the policy objective that the RPM should reflect the market value of the gas at the taxing point. We request further consultation with Treasury in this area to ensure no unintended consequences arise in these circumstances. The solution in achieving symmetry may involve allowing the Extension Project's integrated GTL costs to be reasonable apportioned with Original Project's costs, achieving a similar outcome as if they were one integrated GTL operation.

4.3 The Taxing Point

Extension of the ringfence to a point of sale would introduce a number of elements unrelated to resource recovery and create uncertainty about the extent and nature of eligible deductions for a broad range of expenditures associated with downstream activity. The appropriate taxation point for a resource tax is at the first point where there is a marketable product from the recovery of petroleum. Product-based definitions reflect the fundamental principle that the PRRT should not extend to manufacturing processes.

Report into the Operation of the PRRT, Minister for Resources (1992), p.14

The issue of the scope of the PRRT has been addressed on a number of occasions since the regime was introduced in the mid 1980's. The extract above was from a report prepared by the Minister for Resources in 1992 in the operation of the PRRT following changes that were made in 1990. It clearly outlines the intended scope of the regime and the refection of any extension of its scope.

Any extension of the project ringfence to include liquefaction processes, the storage of LNG, transport (including shipping) and marketing activities would fundamentally undermine the intended scope and operation of the tax, which is to tax super profits attributable to the resource that is extracted.

PRRT is not intended to be a tax on value adding activities (other than those activities directly related to the recovery of the underlying resource). In effect any extension would apply a second layer of company income tax on the resource extraction and liquefaction processes.

4.4 Movements in Gas Prices

The Treasury Consultation Paper notes that a policy question is the operation of the 50:50 split in a high price environment. In particular, it poses the question of whether an alternative profit split is appropriate in a higher LNG price environment. A comment contained in the Callaghan report is that when resource rents are high, there is potentially an under taxing of the upstream portion of the project. No evidence is provided to support this observation.

The Arthur Andersen report briefly considered the question of the impact of price movements and whether they should be addressed in the RPM.

> *"The study examined various methods by which a derived gas transfer price could be stabilised given fluctuating LNG price movements. Some of these proposals involved setting a cap or floor on gas transfer price movements given changes to LNG prices, or setting price or growth paths for the gas transfer price in response to shifting market conditions. These options were administratively complicated and could be avoided if contractually the parties minimised these LNG price risks by removing pricing variances in the bilateral contracts themselves. None of these options were adopted, as the study concluded that predetermining a gas transfer price path was a more subjective process which had the potential to send incorrect pricing signals inconsistent with the state of current energy markets."*

Arthur Anderson Report, p.15

In the context of the discussion in the Treasury Consultation paper, the relevant issue is where rents are generated within an integrated project. Furthermore, the paper seems to imply that the profit split should be adjusted (presumably in favour of the upstream) in a high price environment, however it remains silent about the consequences of a low price environment. By implication, it would seem to suggest a floor should be set at 50/50, with consideration given to some form of adjustment mechanism if price rises above an undefined level.

In addressing this question, it is important to consider the following factors:

- Where the value genuinely accrues within an integrated project, noting that without downstream infrastructure, the benefits of a higher LNG price would not exist.
- The upstream phase of a project already receives half of the benefit of a price rise.
- Separately, the operation of the core PRRT provisions see any price increase reflected in higher payments to governments. In addition, a higher price environment also leads to higher company tax payments.

As a final observation, APPEA would note that any consideration to modify the residual profit split to account for movements in prices will inevitably increase the complexity of the existing methodology which would seem to be at odds with a stated objected of reducing complexity and improving transparency.

APPEA believes the present provisions operate in the most effective way possible, hence no changes are necessary.

4.5 Transparency/Compliance

The Treasury Consultation Paper raises a number of issues associated with transparency and compliance with the GTP provisions. It is suggested that public confidence in PRRT can be strengthened through greater public accountability.

Transparency

From a transparency perspective, the community’s confidence in the effective operation and integrity of the PRRT regime is best served through a rigorous monitoring and compliance role played by the ATO. In addition to the ATO’s overarching responsibilities and compliance powers connected with PRRT, the agency plays an important role in the various stages of the GTP process.

Specifically, the ATO is engaged at an early stage of the process with taxpayers. Such engagement is acknowledged by industry as providing significant benefits to both the ATO and individual project participants. The ATO has skilled up its knowledge and understanding of the LNG industry over the last two decades, much of which has been as a result of engaging directly with taxpayers around the GTP. The existing powers held by the ATO to ensure there is appropriate taxpayer compliance provides a sound basis for ongoing monitoring of the industry’s activities. The ATO is also subject to regular scrutiny and accountability, including through the Senate committee processes.

APPEA would note the ATO has recently included a tax gap analysis for PRRT within its annual review of taxpayer compliance. The ATO notes that PRRT revenues are highly variable due to commodity movements and project development cycles, meaning PRRT revenue is particularly sensitive to commodity prices, exchange rates and development costs. The ATO indicates that it has a high level of coverage of the PRRT tax base, having entered into annual compliance arrangements (ACAs) and advance pricing APAs with some PRRT taxpayers. They conclude that they have observed a high level of willing participation with correctly registering, lodging and paying on time. The reported tax gap for PRRT was 2.0 per cent in 2015-16 – this is very low compared with many other taxes. This reflects positively on how the present regime is operating.

There are a number of processes in place that specifically deal with taxpayer transparency. The annual release of taxpayer data by the ATO is one approach. While providing a high level snapshot of the company tax and PRRT payments made by individual taxpayers, it remains important for the information to be viewed in context. For example, for companies engaged in large scale petroleum operations, the timing and positioning of individual taxpayers within the investment cycle for projects has an important bearing on the level of income tax and PRRT paid. The further release of information by the ATO without important supporting contextual information has the potential to cause more confusion rather than providing clarity.

There has been an increase in the number of taxpayers with oil and gas operations becoming signatories to the voluntary tax disclosure process. This includes companies with interests in LNG projects. The benefit of such an approach is that it provides taxpayers with the means to provide information and explain the factors impacting on the amount of tax paid (or will be payable in the future).

Suggestions that taxpayers should be compelled to release pricing information associated with PRRT calculations would present significant challenges. In terms of the GTP, there will be a range of factors leading to variations in prices for different projects (and in some cases, for participants within projects). These factors are likely to be understood by the ATO, however public disclosure would merely create confusion with little or no public benefit. Furthermore, Australia's ability to effectively compete in global markets would be significantly eroded if taxpayers we required to publicly release price or cost information.

Compliance

Treasury has sought comments associated with the sharing of information. Advice from APPEA member companies suggests that the existing arrangements do not present an impediment to the effective operation of the RPM provisions. In the event that difficulties are encountered, taxpayers have the ability to work with the ATO to ensure effective outcomes can be achieved.

Deloitte.

Australian Petroleum Production & Exploration Association Limited

Transfer pricing assessment of the factors determining the existence (and potential calculation) of a comparable uncontrolled price for feedstock gas in offshore gas to liquids projects in Australia

17 May 2019

Contents

1 Executive summary

Engagement Summary

1.1 On 5 April 2019, The Treasury of the Australian Government ('**Treasury**') released a consultation paper on Treasury's review into the gas transfer pricing ('**GTP**') arrangements for Petroleum Resource Rent Tax ('**PRRT**') purposes ('**Consultation Paper**'). This GTP review implements the recommendation of an earlier independent review led by Michael Callaghan AM PSM into the PRRT regime more broadly ('**Callaghan Review**').

1.2 In connection with Treasury's GTP review, we have been instructed by Australian Petroleum Production & Exploration Association Limited ('**APPEA**') to provide an advisory report to APPEA on the application of comparable uncontrolled prices ('**CUPs**') for feedstock gas in offshore gas to liquids ('**GTL**') projects in the context of the GTP arrangements of the PRRT (hereafter referred to as '**Report**').

1.3 The basis on which we have prepared the Report is set out at **Appendix A**. The background to the present Treasury GTP review and the earlier Callaghan Review, together with the scope of the Report, are set out in **Appendix B**.

Legislation and guidance

1.4 In preparing this Report, we have relied on the following legislation and guidance:

- *Petroleum Resource Rent Tax Assessment Act 1987 (Cth)* ('**PRRT Assessment Act**')[1]
- *Petroleum Resource Rent Tax Assessment Regulation 2015 (Cth)* ('**PRRT Regulation**')[2]
- "*Transfer Pricing Guidelines for Multinational Enterprises and Tax Administrations - 2017*" published by the Organisation of Economic Co-operation and Development in July 2017 (the '**OECD Guidelines**')
- *"Aligning Transfer Pricing Outcomes with Value Creation – Actions 8-10 2015 Final Report"* published by the OECD in 2015 ('**Actions 8-10 Reports**').

The legislative background to the PRRT is set out at **Appendix C** and the application of the OECD Guidelines for the purposes of this Report is included at **Appendix D**. This Report should be read in conjunction with these Appendices.

Summary of advice

1.5 The Callaghan Review acknowledged the application of the OECD Guidelines for the purposes of finding an arm's length price of gas at the taxing point, defined by the PRRT Assessment Act and the associated PRRT Regulation, and specifically references the application of the CUP method.[3] The Callaghan Review also acknowledges the difficulty in finding an 'uncontrolled' comparable transaction, especially for offshore integrated projects, noting that there is no uncontrolled transfer of natural gas or sales into liquefied natural gas ('**LNG**') projects in the North West Australia region to observe.[4]

1.6 In order to employ the CUP method, the uncontrolled transaction must be reliable and publicly available. Broadly, our experience has shown that it is notoriously difficult to find CUPs and, even if potential CUPs can be identified, performing comparability adjustments to enhance the reliability of

[1] Incorporating the amendments made by the *Treasury Laws Amendment (2019 Petroleum Resource Rent Tax Reforms No. 1) Act 2019*.
[2] The PRRT Regulation was remade in 2015. The original form of the regulation was the *Petroleum Resource Rent Tax Assessment Regulations 2005* ('**2005 Regulations**') which, by operation of the *Legislative Instruments Act 2003*, had been due to 'sunset' on 1 April 2016. The PRRT Regulation remade the 2005 Regulations with some minor changes to modernise the drafting style, reduce compliance costs for industry and ensure that the PRRT Regulation is fit-for-purpose. Given the genesis of the (2015) PRRT Regulation, it will be necessary and relevant, where applicable, to refer to the predecessor 2005 Regulations and its Explanatory Statement.
[3] Callaghan Review, p 138.
[4] Ibid.

the CUPs is challenging, particularly in the gas industry. While the CUP method may be more easily applied for example in other industries or in relation to other transactions, and even in relation to LNG sales (which occur further downstream), there are a number of factors which present significant practical challenges to the application of a CUP for the purposes of determining an arm's length price for feedstock gas. These factors are assessed and analysed with reference to the OECD Guidelines.

1.7 The CUP method is one of the OECD endorsed transfer pricing methods. The OECD Guidelines provide stringent requirements for reliable application of the CUP method. The OECD Guidelines state that in order to reliably apply the CUP method, comparability analysis should be undertaken to compare the controlled and uncontrolled transactions, with particular regard to five factors.

1.8 In the Australian market there is very limited, if any, availability of independent comparables for feedstock gas sales. LNG sales are distinct to feedstock gas as they occur at a later point in the overall supply chain. An assessment needs to be made of the value added contributions that have been made to the product from the point of feedstock gas to (conversion into) LNG, which substantially impact price.

1.9 In the event a potential CUP can be identified, the likelihood of the comparability factors being satisfied is limited, due to the complex nature of the industry. The broader industry determinants which significantly impact the comparability of transactions as well as the factors which impact the price between feedstock gas and domestic gas result in the limited application of CUPs in the context of the PRRT legislation.

1.10 Where a potential CUP transaction can be identified and broadly is able to meet the comparability factors, subject to adjustments, there is then great difficulty in ensuring that any required adjustment is reliable and sustainable.

1.11 Finally, following the determination that finding reliable CUPs is not possible as a primary method for determining the amount of assessable petroleum receipts, the residual pricing method ('**RPM**') was considered. The RPM recognises that Australian gas projects are highly operationally integrated and economically interdependent and considers the relative contributions of both the upstream and downstream stages of integrated GTL projects. This is in line with the OECD's Actions 8-10 Reports.

1.12 Following the release of the OECD's Actions 8-10 Reports, transfer pricing approaches have evolved to consider the value contributions made by each party to a transaction and the risks borne by both parties. Previously, transactions were considered in isolation or as a one-sided approach. It is now commonly accepted by transfer pricing practitioners, tax authorities and the OECD that in order to determine appropriate arm's length outcomes, consideration must be given to the contributions of both parties through detailed analysis of the functions performed, risks borne and assets owned/utilised by both parties.

1.13 For these reasons the RPM as a theoretical methodology has a number of advantages, as it does not rely on identifying and adjusting external transactions but rather awards a routine return for the standard upstream and downstream activity and then divides the remaining, or residual, profit on a reasonable basis, in order to calculate the amount of the assessable petroleum receipt for the feedstock gas. This method allows both the upstream and downstream stages to participate in the residual profit of LNG i.e. the augmented value of LNG over feedstock gas which is generated through the integrated economic activity of the upstream and downstream stages.

1.14 The RPM as a method has closer alignment with the OECD Profit Split methodology. When considering the most appropriate method, under the OECD Guidelines, to determine the arm's length price for feedstock gas, the economic integration and interdependence of the hypothetical upstream and downstream stages and the value contribution by each hypothetical "party" would favour the use of the Profit Split method. In the absence of reliable CUPs, this provides additional support for the increased use of the RPM in the context of determining arm's length pricing for feedstock gas.

2 Nature of Australian LNG Industry

PRRT context

2.1 The PRRT Assessment Act plainly distinguishes:

- sales gas destined to be used functionally as feedstock for conversion into LNG (referred to as feedstock gas); from
- gas that is processed so that it is suitable for domestic consumption as energy (commonly referred to as 'domestic gas')[5].

2.2 Although domestic gas is captured under the broad umbrella of 'sales gas' as a kind of taxable marketable petroleum commodity for PRRT purposes, that does not automatically mean domestic gas and feedstock gas are homogeneous or interchangeable. The distinction accorded to feedstock gas and domestic gas by reference to their functional use is one of important significance in the scheme of the PRRT Assessment Act.

2.3 Domestic gas is not, and cannot be, subject to the PRRT Regulation (which deals exclusively with feedstock gas that is converted into liquefied product[6]). The taxing point for domestic gas is typically at the outlet flange of the domestic gas plant. The taxable value of domestic gas is determined by reference to the consideration receivable for its sale (if sold at arm's length) at the taxing point or otherwise, its market value at the taxing point (usually by way of netback from the 'city gate price' to the taxing point).[7] This is because domestic gas can immediately be consumed as energy but feedstock gas cannot be immediately consumed because it requires further processing and liquefaction for transport to its intended market (and regasification and odorisation at the destination before entering the local natural pipeline system). The specific composition of the hydrocarbons in the feedstock gas (e.g. the level of residual ethane or other heavier hydrocarbons) that is turned into LNG differs depending on the destination market (e.g. Japanese and European buyers require gas with higher calorific or heating value). This dictates the degree of conditioning required to the feedstock gas before it in fact becomes saleable or marketable LNG. The statute directs that the end functional use of feedstock gas (as distinct from domestic gas) must unequivocally be taken into account in identifying relevant markets from which to source potential CUPs.[8]

2.4 This Section will address the important industry factors that differentiate feedstock gas from domestic gas, as well as other critical industry factors relevant to the identification of potential CUPs.

Gas

2.5 Gas projects, whether they produce feedstock gas or domestic gas, have a complex value chain. Australian gas projects are commonly integrated projects owned and operated by a single entity or a single group of joint venture entities (although there are certainly instances where venturers have varying or non-uniform interests in different parts of the value chain).[9] This structure results in Australian gas projects being highly operationally integrated and economically interdependent. The Australian market has limited competitors as it is a smaller market with fewer functionally discrete competitors, whereas markets such as the US have a number of discrete market players

[5] See the definition of 'marketable petroleum commodity' and 'sales gas' in subsection 2E(1) and section 2 respectively of the PRRT Assessment Act.
[6] See the definition of 'integrated GTL operation' in section 6 of the PRRT Regulation, which is the gateway for engaging the GTL framework (and the hierarchy of valuation methods) set out in sections 19 and 20 of the PRRT Regulation.
[7] See paragraphs 24(1)(b) or (c), read in conjunction with the definition of 'excluded commodity' in section 2, of the PRRT Assessment Act.
[8] See paragraph 23(3)(c) of the PRRT Regulation.
[9] <http://www.spain-australia.org/files/documentos/79_EIA_Australia_7mar2017.pdf>.

who undertake economically autonomous functions within the complete gas value chain. Due to the limited competition in the Australian market the availability of public information is also limited, which is attributed to the focus of Australian gas projects to protect proprietary information, particularly with regards to pricing.

Value Chain

2.6 The gas value chain consists of highly linked, interdependent steps:

- Exploration
- Development
- Production
- Transportation and storage
- Distribution and marketing.

2.7 The above value chain varies significantly for feedstock gas (to be sold as LNG) as compared to domestic gas. The functional intensity of each of the value chain components is significantly greater for LNG projects than for domestic gas. These differences will be discussed in greater detail throughout the Report.

Feedstock Gas (LNG)

Introduction to LNG[10]

2.8 LNG is natural gas in a liquid form that is clear, colourless, odourless, non-corrosive and non-toxic. Natural gas is one of the cleanest energy sources available today. It can be used to replace other fossil fuels such as coal and oil, which emit significantly higher levels of pollutants. LNG is of superior quality compared to domestic gas because it is purer with a higher methane and energy content. LNG is a safer fuel than gasoline and diesel fuel, as it has a limited range of flammability. As a liquid, LNG is not explosive. LNG vapour will only explode in an enclosed space within the flammable range of 5% to 15%.[11]

Australian LNG sector

2.9 In Australia, the LNG industry has rapidly expanded over the last five years as strong project development has increased the scale of the industry. The LNG sector is entirely export focused, with all of its industry revenue generated through sales to foreign markets. These major markets include Japan, China, South Korea and Singapore. The increase in demand in Asian markets has led global LNG prices to surpass domestic gas prices. As a result, Australian LNG producers have been encouraged to allocate the majority of their natural gas to export markets.[12]

2.10 International trade of LNG by Australian producers has traditionally been conducted through long-term contracts linked to oil prices. The origins for the oil-linked long-term contract pricing structure are attributed to Japan's importation of LNG as a replacement for crude oil. Once other Asian economies began importing LNG, long-term oil-linked contracts were already well established as the accepted pricing mechanism and still prevail today as the primary long-term LNG pricing mechanism. During the period 2008 to 2017, spot and short-term LNG offtake contracts grew from 20 to 30 percent of all volumes exported.[13] In comparison the developed spot market pricing of natural gas observed in North America, and to a lesser extent Europe, has competing sources of gas which are priced in 'hubs' (US Henry Hub or the UK's National Balancing Point) and also acts as the pricing and delivery points for natural gas futures contracts.[14] Australia does not have a similar

[10] <https://www.appea.com.au/oil-gas-explained/oil-and-gas/what-is-liquefied-natural-gas-lng> and <https://www.originenergy.com.au/blog/about-energy/coal-seam-gas.html>.
[11] "2018 World LNG report," International Gas Union, <https://www.igu.org/sites/default/files/node-document-field_file/IGU_LNG_2018_0.pdf, accessed June 28, 2018>.
[12] IBISWorld Industry Report "Liquefied Natural Gas Production in Australia", September 2018 p.6.
[13] Natasha Cassidy and Mitch Kosev, 'Australia and the Global LNG Market' Reserve Bank of Australia, March 2015 pg 38. Retrieved from <https://www.rba.gov.au/publications/bulletin/2015/mar/pdf/bu-0315-4.pdf>.
[14] Ibid 36.

publicly traded index for domestic gas. Therefore, it is reasonable to conclude that the majority of feedstock gas is ultimately priced with reference to published oil indices.

2.11 Cost competitiveness is especially important in a LNG project. In order to produce LNG with sufficient economies of scale, significant capital expenditure (typically billions of dollars) is required to develop gas reserves, transport the extracted gas to an appropriate facility, process and store the gas using onshore facilities, and market and transport the gas for sale.[15] The level of expenditure incurred to run such operations is reflective of the value-add generated in the downstream process. The reliance on long-term contracts (typically 15 or 20 years) also provides the producer a degree of certainty to recover the substantial upfront expenditure associated with developing greenfield gas projects, and many Australian LNG projects under construction were, in part, financed by customers who wanted to secure their long-term LNG supply.[16] The exact details of the oil-linked pricing for long-term contracts are negotiated confidentially between producers and customers and such information is therefore not publicly available or accessible.[17]

2.12 It is also broadly recognised, through observed industry practice, that in order to advance projects and reach final investment decision ('**FID**'), common practice is to secure substantial long-term offtake from buyers (i.e. prior to FID). Historically, achieving long-term offtake agreements has often been considered a pre-requisite to reaching FID for LNG projects worldwide. While this practice is observed and acknowledged, there are not necessarily specific volumes attributable to reaching FID as this is considered on a project-by-project basis. The importance of this stage within the LNG lifecycle can affect the bargaining power of buyers / sellers negotiating the terms of long-term purchase contracts.

LNG: Unconventional Gas

2.13 Unconventional gas is natural gas sourced from deposits, or via means, that are different from the traditional sources or means of obtaining gas. For example, in Australia, coal seam gas ('**CSG**') is an unconventional gas (as opposed to another type of unconventional gas, such as the 'shale gas' that is produced in North America). CSG is gas that is present in coal deposits.[18]

2.14 There are important differences between CSG and conventional or 'rich' natural gas. CSG has a lower calorific value than conventional natural gas. 'Calorific value' refers to the amount of energy released when a specific volume of gas is combusted.[19] This means that one volumetric unit of CSG produces less energy than conventional natural gas, all things being equal. Due to this lower calorific value, CSG is commonly referred to in the market as 'lean LNG' (as opposed to 'rich LNG', which is used to refer to LNG sourced from conventional natural gas).

2.15 The uncertainties and physical characteristics of CSG resulted in a widespread view that CSG (i.e. lean gas) should command lower pricing than rich gas. This view has been noted by the Australian government[20] and industry data broker S&P Global Platts[21], from an export perspective.

Domestic gas

Feedstock gas vs domestic gas

2.16 Whilst the exploration, development and production elements of the value chain are broadly comparable for feedstock and domestic gas, there is a substantial distinction in the remaining processes of the value chain between the two types of gas.

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[15] University of Texas at Austin – Center for Energy Economics, "The LNG Value Chain". Retrieved from <http://www.beg.utexas.edu/energyecon/lng/LNG_introduction_08.php>.
[16] Above n 13.
[17] Above n 13.
[18] <https://www.appea.com.au/oil-gas-explained/oil-and-gas/what-is-coal-seam-gas/>.
[19] <https://www.nationalgridgas.com/data-and-operations/calorific-value-cv>.
[20] Michael Priestley, 'China's reliance on Australian LNG exports' Parliament of Australia. Published 16 December 2009, updated 6 January 2010. Retrieved from <https://www.aph.gov.au/About_Parliament/Parliamentary_Departments/Parliamentary_Library/pubs/BN/~/link.aspx?_id=4BA6F23AEFCA4EC688372C6D2BFF6269&_z=z#_Toc248718089> pg. 5.
[21] LNG Daily S&P Global Platts, "Asia LNG: JKM Little Changed As Market Re-Assesses Heatwave-Related Demand", 2018, pg 5.

2.17 While domestic gas is transported via pipelines domestically, feedstock gas has to undergo further liquefaction, transportation, storage, regasification and distribution. These processes unlock significant value to eventually transform the feedstock gas into LNG. Due to the aforementioned increase in demand in Asian markets, LNG prices have surpassed domestic gas prices. Although domestic gas and feedstock gas may be similar[22] in their characteristics at the extraction point, there is a substantial amount of additional economic uplift that occurs to feedstock gas as opposed to domestic gas. This economic uplift reflects that gas producers can operate at different points in the supply chain (i.e. sometimes performing one function in that chain and sometimes integrating vertically into a number of functions). This differentiation reflects that producers may sell at different points in the value chain, i.e. feedstock gas is sold as a raw material or input for the supply chain whereas domestic gas is sold as a consumable.

2.18 The emergence of LNG exports as a significant portion of Australian commodity exports reflects that feedstock gas and domestic gas are influenced by different market factors and economic conditions. The composition of Asian energy demand has significantly changed over the last decade.[23] In 2013, localised sources of production account for around 70% of global natural gas consumption. However, many areas in Asia are geographically removed from substantial natural gas reservoirs making it expensive or impractical to rely on domestic gas resources. LNG emerged as a viable alternative for Asian consumers, which represent 75% of global LNG demand.[24] The market for domestic gas has not been influenced by the same economic conditions and demand factors, which, based on our experience, limits the comparability of the LNG industry (and by inference feedstock gas) and the domestic gas industry.

Australian government gas regulations

2.19 The Australian government has put mechanisms in place to regulate domestic gas quantity and price, which ultimately impacts the Australian domestic gas market conditions.

2.20 Under Western Australia's domestic gas reservation policy the State Government requires new gas developments to supply the equivalent of 15% of their LNG exports to the Western Australian domestic gas market. Although the policy is not formalised in legislation, it is enforced by the Government via its right to deny access to land (or potentially state waters) for LNG plants and infrastructure.[25] LNG projects must demonstrate their ability to comply with the policy as a condition for approval. The key aim of this policy is to secure higher levels of domestic gas supply and thereby maintain lower domestic gas prices.

2.21 Additionally, the Federal Government has enacted the Australian Domestic Gas Security Mechanism to ensure sufficient supply of natural gas to meet the forecast needs of energy users within Australia. The mechanism has been inserted into the Customers (Prohibited Exports) Regulations to ensure that exportation of LNG from Australia is prohibited during a domestic shortfall year unless permission has been granted.[26]

2.22 These policies may serve to alter the economic characteristics of the domestic gas market, because the price and volume of gas available is not only controlled by the influences of supply and demand, but also by government intervention. The Callaghan Review specifically acknowledges that gas sold due to government policy results in a price for gas that is not comparable.[27]

[22] <https://www.aemo.com.au/-/media/Files/Gas/DWGM/2017/Gas-Quality-Guidelines-Version-10.pdf>.
[23] Above n 13.
[24] Ibid.
[25] Government of Western Australia Department of Jobs, Tourism, Science and Innovation *"WA Domestic Gas Policy"* <https://www.jtsi.wa.gov.au/economic-development/economy/domestic-gas-policy>.
[26] *Customers (Prohibited Exports) Regulations* 1958, Division 6, section 13GC.
[27] Callaghan Review, p 90.

3 Determining Assessable Petroleum Receipts

Application of CUP

Overview

3.1 Treasury's Consultation Paper builds upon the recommendations of the Callaghan Review of the PRRT. The Callaghan Review recommended strengthening the scope to use a CUP as the primary method of setting the gas transfer price in line with international best practice. Whilst CUPs are internationally recognised as the most appropriate transfer pricing valuation methodology, Treasury has stated that the overall objective of the gas transfer pricing regime should be to find a reasonable estimate of an arm's length outcome based on the most reliable information available. It follows that the practical limitations of obtaining reliable comparable uncontrolled data may restrict the utility of CUP as a method, and make another method of pricing more suitable.

3.2 The CUP method is a particularly reliable method where an independent enterprise sells the same product (i.e. in an uncontrolled transaction), in the same circumstances as is sold between two associated enterprises (i.e. a controlled transaction). It may be difficult to find a transaction between independent enterprises that is similar enough to a controlled transaction such that there are no differences which have a material effect on price. For example, a minor difference in the property transferred in the controlled and uncontrolled transactions could materially affect the price. When this is the case, adjustments will be required to the extent they are able to be performed. The extent and reliability of such adjustments will affect the relative reliability of the analysis under the CUP method.

3.3 In considering whether controlled and uncontrolled transactions are comparable for purposes of the CUP method, regard should be had to the effect on price of broader business functions other than mere product comparability (i.e. all of the factors relevant to determining comparability as listed in **Appendix D**). Where differences exist between the controlled and uncontrolled transactions or between the enterprises undertaking those transactions, it may be difficult to determine reasonably accurate adjustments to eliminate the effect on price. The difficulties that arise in attempting to make reasonably accurate adjustments should not routinely preclude the possible application of the CUP method. Every effort should be made to adjust the data so that it may be used appropriately in a CUP method.

Applicability

3.4 To apply a CUP method to determine the amount of the assessable petroleum receipt in respect of feedstock gas at the taxing point, it would be necessary to identify a transaction with:

- Prices charged by the selling entity in the same or similar transactions with an independent party ('**Internal CUP**');
- Prices paid by the purchasing entity in the same or similar transactions with an independent party (Internal CUP); or
- Prices paid in the same or similar transactions between two independent third parties ('**External CUP**').[28]

In the event a transaction can be identified as set out above, assessment would then need to be made of whether the comparability factors, as set out in Appendix D, are met with respect to the potential CUP.

[28] In a PRRT context, the notional hypothetical sale occurring at the taxing point between the upstream and downstream stages of an integrated GTL operation would be the controlled transaction for present purposes. An example of an uncontrolled transaction may be any actual sale by the upstream operation of the same project to a third party (i.e. a possible internal CUP).

Comparability factors

3.5 The below table sets out the comparability factors, in order of importance, which must be considered under the OECD Guidelines in order to determine whether a CUP exists. Note, the comparability factors in the PRRT Regulation overlap with those set out in the OECD Guidelines (cf. Appendices C and D); therefore consideration of the OECD Guidelines comprehensively encompasses the requirements of the PRRT Regulation. The table also provides examples of differences between controlled and uncontrolled transactions that are commonly observed in the industry, which often preclude the possible application of the CUP method.

3.6 The below table is not exhaustive however it highlights various industry specific factors which impact the assessment of whether a CUP exists. The table also demonstrates how differences between controlled and uncontrolled transactions may be too significant (such that no CUP exists), or such differences may not be able to be reliably adjusted for which would again preclude the reliable application of the CUP method.

Comparability Factors	Examples	Explanation	Report reference
1. Characteristics of property	• Rich vs lean	It is generally accepted that specifications of gas are comparable. An exception to this are the recognised differences between 'rich' gas as compared to 'lean' gas, which has a lower calorific value. Where this difference exists, reasonably accurate adjustments would be required to ensure comparability.	Paragraphs 2.13-2.15
2. Functions, assets and risks	• Ultimate customer (export vs domestic)	The OECD's Actions 8-10 Reports reinforce the critical importance of requiring a similar functional profile to ensure comparability. Feedstock gas should not be considered comparable to domestic gas, on the basis that there is a very different functional profile for the value chain of each gas. The value chain of LNG projects (feedstock gas) require significantly more capital assets (e.g. pipelines, liquefaction plant, access to shipping/terminals, marketing intangibles specific to overseas markets). LNG projects also need additional functions to be undertaken in order to ensure sale to the ultimate export customer (e.g. midstream / downstream processing, management of shipping, maintenance of customer relationships). Finally and most importantly, the significant additional risks present in the LNG value chain (e.g. shipping risk, currency risk, damage to assets, sovereign risk, liquefaction plant operating reliability risk) are not comparable to domestic gas. The potential for reasonably accurate adjustments for such significant deviations is limited.	Paragraphs 2.8-2.12 & 2.16-2.18
3. Contract terms and conditions	• Oil-linked pricing • Volume • Duration	Feedstock gas is converted into LNG, which is ultimately priced with reference to published oil indices and therefore is subject to different market factors, for which it is difficult to make reasonably accurate adjustments. Volume discounts are financial incentives provided to encourage buyers to purchase larger quantities and are often observed in the commodity sector.[29] Additionally, securing offtake (purchase) for a longer	Paragraph 2.10

[29] <https://www.investopedia.com/terms/v/volume-discount.asp>

Comparability Factors	Examples	Explanation	Report reference
	• Assignment of risk	duration may also attract a discount, particularly in an industry which commonly observes 20-year purchase agreements as well as short-term offtakes. Both of these examples necessitate reasonably accurate adjustments. Allocation of risk in contracts can differ greatly (e.g. Incoterms for LNG, performance risk, take or pay) and depending on the specific difference, may not be able to be adjusted for.	
4. Economic conditions	• Government intervention • Propensity for distressed buyers / sellers to exist	Government intervention in the domestic gas market can result in unquantifiable change in the economics of the market. Ensuring supply into the domestic gas market or prohibiting exportation of LNG may result in the price not being indicative of market driven pricing because the transaction may not be undertaken on a profit maximising basis. In a distressed purchase / sale, the price of the product purchased / sold can be considered somewhat artificial as it was not sold under open and competitive market conditions. Normally this requires a willing but not anxious buyer and seller. The gas market, both domestically and abroad, has on occasion experienced these adverse market conditions.[30]	Paragraphs 2.19-2.22
	• Geographic • Ultimate customer (export vs domestic)	The demand from particular geographic regions, whether domestic (East coast vs West coast) or abroad (China vs Japan) can influence and affect the prices paid in transactions. Given that the market is significantly different for domestic gas as compared to feedstock gas, the economic conditions comparability factor is not usually satisfied and it is difficult to determine the impact on price of these varying economic conditions.	Paragraph 2.9-2.10 Paragraph 2.18
5. Business strategies	• FID	Factors of importance to the business can significantly impact the price agreed for a transaction. Particularly for LNG Projects approaching FID, securing supply is of utmost importance and can result in the buyer having greater bargaining power to secure a lower price. By securing the lower price the business is able to increase its probability of reaching FID and ensuring the success of the project, which is difficult to value.	Paragraphs 2.12

[30] East Coast gas crisis <https://www.accc.gov.au/speech/recognising-australias-east-coast-gas-crisis> and Fukushima <https://www.reuters.com/article/us-japan-kansai-elec/japans-kansai-electric-to-cut-lng-deals-as-it-boosts-nuclear-power-idUSKCN1IQ17J>

Internal and External CUPs

3.7 Paragraph 3.4 of this Report identifies the three potential transaction types that could be considered a CUP and these are referred to as either Internal or External CUPs. There are observed difficulties in identifying both types of CUPs, due to the nature of the Australian gas industry and the structure of Australian gas projects.

3.8 Given that most Australian LNG projects that produce feedstock gas are owned and operated by a single entity or joint venture group, it is difficult to identify any feedstock gas transactions (either sales to third parties or purchases from third parties) to assess as a potential Internal CUP (paragraph 2.5). Furthermore, there is currently no observable market for feedstock gas transfers that could be relied on to identify transactions that may constitute an External CUP. Most Australian gas projects are expected to operate for a number of decades and therefore it is unlikely that projects will become less operationally integrated or economically interdependent. This supports the industry view that potential CUPs are unlikely to exist in future years as well.

3.9 Additionally, due to the limited competition and protection of proprietary information within the Australian gas industry, it is also difficult to identify External CUPs. In the rare event that potential External CUPs can be identified, there are still the difficulties in satisfying the comparability factors and/or performing reliable adjustments to account for such differences.

Adjustments

3.10 The above table addressed the difficulty in making adjustments to a potential CUP. Two considerations should be made when determining whether a reasonably accurate adjustment can be made; (1) is the adjustment reliable and robust and (2) is the adjustment sustainable if applied on an ongoing basis.

3.11 We have observed in negotiations with the Australian Taxation Office ('**ATO**') on transfer pricing Advance Pricing Arrangements ('**APAs**') that where a potential CUP has been identified, the application and calculation of necessary adjustments often cannot be agreed upon. The complexities arising from ensuring that any such adjustments are reliable and able to be made year on year has created significant road blocks in negotiations.

Reliable

3.12 Being able to make reliable adjustments is difficult for a number of the examples above. Quantifying the value of the difference is often not an exact science and may undermine the application of the CUP entirely.

3.13 Some adjustments observed in the industry are for: volume, duration, timing and shipping. However, based on our industry experience, being able to adjust for qualitative factors such as economic conditions or business strategies is significantly harder.

Sustainable

3.14 Given that PRRT is an annual tax, consideration must be given to whether the adjustment can be applied over multiple years. Some adjustments may need to be calculated on a year on year basis and this creates additional complexities in ensuring the reliability of the adjustment.

APA Conclusion

3.15 Data from the 2017-18 financial year has indicated that it has taken, on average, approximately 2 years 4 months to conclude a unilateral APA.[31] Amongst an indicator of time delays, this data is also suggestive of the difficulty in achieving consensus between the taxpayer and the ATO about a comparable price and agreeable reliable adjustments. Industry experience also illustrates that commodity APAs have been historically lengthier due to the difficulty faced in agreeing on adjustments. When looking at the unique economic characteristics of commodity transactions, this trend is unsurprising.

[31] <https://www.ato.gov.au/Business/International-tax-for-business/In-detail/Advance-pricing-arrangements/?anchor=APA_and_MAC_statistics>

Other Examples of Accepted / Rejected CUPs

3.16 As indicated in Appendix D, where it is possible to identify sufficiently comparable uncontrolled transactions, the CUP method is the most direct and reliable way to apply the arm's length principle and is therefore preferable over all other methods.[32] However, recent landmark transfer pricing cases have acknowledged that identifying a CUP goes beyond finding the same or similar product. The judgement provided in the *SNF* case acknowledged that identifying a CUP extends to ensuring that those factors which may influence price (i.e. those included in the OECD Guidelines as the comparability factors) must be the same or reliably similar.[33] The ATO has publicly expressed its concerns on taxpayers' attempts to apply the CUP method, in the context of commission rates. The ATO states that the comparability standard to establish reliability is higher when applying the CUP method.[34] The ATO's concern is that an absence of information to evidence the comparability of the uncontrolled transaction may result in merely demonstrating that a 'similar' transaction exists, rather than a 'comparable' transaction.[35] The ATO notes that the comparability standard should be met with reference to the OECD's comparability factors.[36]

3.17 Following the release of the OECD's Actions 8-10 Reports, the OECD Guidelines recognised that a 'quoted price' could be relied on to determine an arm's length price for commodity transactions. However, there are no quoted prices for Australian domestic gas or feedstock gas. If there are CUPs they are negotiated confidentially and not available in the public domain and therefore not able to be relied on.

3.18 Internal CUPs are often considered for potential application as it is generally easier to obtain the additional information required to confirm whether the comparability factors are met between the controlled and uncontrolled transactions. However, as always, the application of an Internal CUP is subject to the particular facts and circumstances of the transaction. In the gas industry there are a number of industry factors, which can significantly impact the price, but which are difficult to quantify and reliably adjust for.

3.19 The use of the CUP method in other industries or to support other types of controlled transactions is also limited. For example in relation to Hard to Value Intangibles, the application of a CUP is more often than not impossible given there are no identifiable potential comparable arrangements in the public domain, making a profit split a much more appropriate and viable method to adopt to price such transactions.

3.20 In our industry experience, External CUPs are most commonly identified in relation to financing arrangements. The application of the CUP method in relation to financing arrangements is possible for a number of reasons. Firstly, there are databases containing the relevant information about uncontrolled financing arrangements (e.g. Bloomberg) and where necessary, comparability differences can be quantified and adjustments performed to account for differences in loan features (e.g. term, currency). Secondly, the large volume of publicly available information included in the databases results in a greater likelihood that a CUP can be identified. However, recent case law has reinforced how critical it is to satisfy the comparability requirements.

3.21 The *Chevron* case[37] demonstrates how strictly the comparability requirements for the application of the CUP method are applied by the courts. In this case, both the taxpayer and the Commissioner put forward expert witnesses that identified and analysed a number of comparable transactions to support their positions in relation to the transaction in question, being the interest charged on an inbound loan arrangement. The Court rejected the CUPs presented by both sides on the basis that none of the transactions identified were considered to be sufficiently comparable. Transactions identified by the expert witnesses were rejected for various reasons, including differences in the size of the loans, the industry of the borrower, the financial positions of the parties involved in the transactions and the contractual terms (e.g. loan covenants).

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[32] OECD Guidelines, paragraph 2.15.
[33] *SNF (Australia) Pty Ltd v Commissioner of Taxation* [2010] FCA 635.
[34] PCG 2017/1, paragraph 117.
[35] Ibid, paragraph 118-119.
[36] Ibid, paragraph 119.
[37] *Chevron Australia Holdings Pty Ltd v Commissioner of Taxation* (No 4) [2015] FCA 1092.

Conclusion

3.22 In summary, in the event that a potential CUP can be identified, the likelihood of satisfying all five comparability factors is considered to be very low. The prevalence of differences that preclude the application of a CUP in the gas industry is observed to be relatively high, when compared to other industries.[38]

3.23 Furthermore, making adjustments to the potential CUP is extremely difficult due to the complex nature of the adjustments and industry. When considering the reliability and sustainability of such adjustments it is likely to result in possibly undermining the identified potential CUP. As outlined in **Appendix D**, the OECD Guidelines recognise that the need to perform numerous or substantial adjustments to key comparability factors may indicate that the third party transactions are in fact not sufficiently comparable.[39]

3.24 Therefore, it is our experience that the CUP method is of limited use for PRRT application due to the difficulty in:

- Identifying potential CUPs (both Internal and External CUPs);
- Satisfying the requisite comparability factors; and/or
- Making reasonable reliable adjustments to satisfy the comparability factors.

Application of RPM

Overview

3.25 Ordinarily, if there is no APA in place which applies to the feedstock gas, and no CUP that exists in relation to the feedstock gas, the RPM method is used to calculate the gas transfer price.[40] The RPM is akin to a residual profit split approach from a transfer pricing perspective.

3.26 The RPM calculates the price for gas at the PRRT taxing point using a 13 step process.[41] Broadly, the method involves creating a notional integrated operation consisting of an upstream and a downstream entity. A prescribed minimum return for each entity to invest capital and run the business is subsequently calculated. For the upstream entity, the cost-plus price reflects the minimum price they would sell feedstock gas from the PRRT project. For the downstream entity, the netback price reflects the maximum price they would be willing to pay for the feedstock gas.

3.27 The residual profit is the difference between the cost-plus price and the net-back price. The residual profit is split 50/50 to arrive at the gas transfer price. Where the cost-plus exceeds the netback price and the notional project is making a loss, the netback price is the RPM price. The calculation of the RPM is:

$$Gas\ transfer\ price = \frac{cost\ plus\ price + net\ back\ price}{2}$$

3.28 Notably, the RPM method is a hybrid of two commonly recognised OECD transfer pricing methods – the cost plus method[42] and the resale price method.[43] It incorporates the cost-plus and netback calculations to determine the value of sales gas as it leaves the PRRT ring-fence.

3.29 It has been noted that the 50/50 split is an arbitrary allocation and no theoretical basis exists for determining how the residual profit should be split between the netback and cost plus prices to arrive at a single price.[44] This is mainly reflective of the fact that when the regulations were developed, there was minimal prior experience to draw from, and an equal split was the most equitable and objective way to reflect the integrated and interdependent nature of an integrated GTL operation.

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[38] For example, the Pharmaceutical industry is explicitly regulated in all of the major global markets primarily to ensure product quality but also to regulate price and this results in a higher prevalence of potential CUPs because the comparability factors are more likely to be satisfied. A McGuire, "Price Regulation and Pharmaceuticals" (Oxford Research Encyclopaedia of Economics and Finance, 2018)
[39] OECD Guidelines, paragraph 3.51
[40] Subsections 19(5) and 20(5) PRRT Regulation
[41] Section 30 PRRT Regulation
[42] OECD Guidelines, Subsection D.1
[43] OECD Guidelines, Subsection C.1.
[44] Explanatory Statement to the 2005 Regulations, pg. iii.

Applicability

3.30 Although the Callaghan Review highlighted that the residual profit element could be more accurately apportioned, the method itself remains in line with recognised OECD methods and is necessary as an alternative, when CUPs and APAs are not in place. The RPM also recognises that Australian gas projects are highly operationally integrated and economically interdependent, which necessitates the application of a method that recognises these industry factors.

3.31 The RPM considers the relative contributions of both the upstream and downstream, which is in line with the OECD's Actions 8-10 Reports and the profit split ('**PS**') method. The advantage of the RPM is that it does not rely on the use of difficult to identify, obtain and adjust external transactions. It awards a routine return for the standard upstream and downstream activity and then divides the remaining, or residual, profit. In principle, this approach is akin to the PS method, with the exception of using a fixed percentage to determine the split of residual profits. The OECD Guidelines provide guidance on the various approaches for splitting the profits when applying the PS method, the most common of which is a contribution analysis.[45]

3.32 However, it is noted that the Callaghan Review discusses the 50/50 split in the current PRRT Regulation, and notes that any review of the current arrangements could examine whether those arrangements are consistent with the current OECD transfer pricing practices.[46] It is beyond the scope of this Report to delve into, or make recommendations on, how to precisely split the residual profit element. However, the application of a pricing methodology akin to a PS is an authorised method under the OECD Guidelines and based on our industry experience, can successfully be applied in complex integrated value chains.

3.33 The Treasury Consultation Paper recognises that "ultimately, the overall objective of the gas transfer pricing regime should be to find a reasonable estimate of an arm's length outcome based on the most reliable information available".[47] The difficulties in identifying reliable CUPs means that the RPM, or a version of it, will be required into the future as a practical alternative method to calculate transfer prices in GTL operations.

[45] OECD Guidelines, Subsection C.3.2.
[46] Section 4.9.5 pg. 94, Callaghan Review.
[47] The Treasury Consultation Paper *Review of the PRRT Gas Transfer Pricing arrangements'* April 2019, paragraph 35, pg. 8.

Appendix A: Basis of our work

The analysis in this Report has been prepared on the basis of all of the following:

- Our work has been performed based on the information, documents and facts (**Information**) provided by APPEA
- APPEA's understanding that a misstatement, omission or change in any of the Information relied on may render the conclusions reached invalid or necessitate (on APPEA's request) a reconsideration of the analysis
- That no foreign taxes of any kind were considered for the purposes of the Report
- That no other tax issues, including income tax issues, were addressed for the purposes of the Report
- That no confidential information relating to a particular project or entity was used or relied on in the preparation of the Report
- The legislation, regulations, cases, rulings and other tax authorities in effect at the date of the review have been considered. Any material changes to those tax authorities (for which Deloitte has no responsibility to advise APPEA) may render the conclusion of the Report invalid or necessitate (on APPEA's request) a reconsideration of the Report
- APPEA understands that the conclusions from the review are not binding on the ATO or the courts and should not be considered a representation that the ATO or the courts will concur with the conclusions
- APPEA understands that Deloitte's responsibility for the Report is limited to the matters described in the Scope of this Report (see Appendix B).

Appendix B: Engagement Details

Background to the Treasury GTP Review

On 30 November 2016, the Australian Government announced an independent review into the operation of the PRRT. The purpose of the review was to assess whether the PRRT is operating as intended, having regard to the need to provide an equitable return to the Australian community from the extraction and sale of Australia's petroleum resources without discouraging investment in exploration and development.[48] This review was led by Michael Callaghan AM PSM and is known as the Callaghan Review.

The Callaghan Review final report, dated 13 April 2017, was released by the Government on 28 April 2017. Amongst other issues, the Callaghan Review discussed the current GTP regulations and their prescribed methodologies for the valuation of gas used in integrated GTL projects (commonly referred to as LNG projects). The Callaghan Review recommended that the current GTP regulations be examined to identify changes that would achieve greater simplicity and transparency, ease of compliance and fair treatment of the economic rent from each stage of an integrated petroleum operation.[49]

The Callaghan Review concluded that further examination should particularly consider:

1. Strengthening the scope to use a CUP as the primary method of setting the gas transfer price in line with international best practice and recent work by the OECD; and
2. Where a CUP is not available, examining the appropriateness of the asymmetric treatment of upstream and downstream operations, the way profits are split between the upstream and downstream, and the rate of the capital allowance in the RPM.

On 2 November 2018, the Government announced in its final response to the Callaghan Review that Treasury will (consistent with the recommendations of the Callaghan Review) undertake a review into the regulations that determine the price of gas in integrated LNG projects for PRRT purposes. The terms and objectives of Treasury's present GTP review are set out in the Consultation Paper.

Scope of Report

We have been instructed by APPEA to identify and discuss the relevant factors that should be considered in determining whether a CUP exists (or can be generated) for feedstock gas used within LNG projects in Australia.

We were asked to:

- examine the factors identified and considered by the ATO in determining whether comparable uncontrolled prices are in existence [see paragraphs 3.5 to 3.6 and Appendices C and D of this Report]
- include examples[50] of where the ATO has both accepted and rejected the existence of CUPs, including in other industries [see paragraphs 3.16 to 3.21 of this Report]
- canvass adjustments that would be necessary to establish a CUP for feedstock gas and comment on how robust and sustainable such a calculation would be in terms of its practical ongoing application [see paragraphs 3.10 to 3.15 of this Report], and

[48] Australian Government *Petroleum Resource Rent Tax Review* Final Report, 13 April 2017.
[49] The Treasury Consultation Paper *Review of the PRRT Gas Transfer Pricing arrangements'* April 2019, pg. 3.
[50] In the event we are able to identify examples.

- discuss the recent OECD approaches to transfer pricing and whether such approaches can be applied in valuing gas within integrated projects in Australia for PRRT purposes [see paragraphs 3.25 to 3.33 and Appendix D of this Report].

Appendix C: Legislation – PRRT

PRRT – Overview[51]

PRRT is levied on the upstream profits of a petroleum project that is subject to the PRRT (a petroleum project generally exists for PRRT purposes when an offshore petroleum production licence[52] is in force).

The tax is imposed in accordance with the PRRT Assessment Act. The PRRT Regulation was subsequently introduced to provide certainty to the industry in relation to the application of the PRRT Assessment Act to integrated GTL projects.

The PRRT is assessed on a project basis. The tax is imposed at a rate of 40% on the taxable profits derived from activities within the PRRT ringfence (which generally include the recovery of petroleum from the project and the production and sale of specified marketable petroleum commodities, namely stabilised crude oil; condensate; sales gas; natural gas; liquefied petroleum gas ('**LPG**'); and ethane). The taxable profit is broadly calculated by reference to the following formula:

Taxable profit = assessable receipts – deductible expenditure – eligible inter-project transferrable exploration expenditure – eligible inter-company transferrable exploration expenditure[53]

This Report relevantly deals with feedstock gas in integrated offshore GTL projects. In this context, feedstock gas refers to 'sales gas' that is further processed into LNG as part of an integrated process. Sales gas exists when a substance that is predominantly methane in a gaseous state at the temperature of 15 degrees Celsius and a pressure of 1 atmosphere, has been processed to the state where it is suitable to be used as feedstock for conversion into LNG.[54] The PRRT Assessment Act prescribes that the taxing point for such sales gas is the point where that gas, being in its final form ready for use as feedstock for conversion into LNG, is subjected to further processing to convert it into LNG.[55] This point is usually just before liquefaction.[56] The taxing point separates the upstream stage of the integrated project (comprising the processes and operations up to that point) from the project's downstream stage (comprising the processes and operations post the taxing point). References to feedstock gas in this Report means sales gas at the taxing point (and the two terms may be used interchangeably).

PRRT – GTP arrangements

The PRRT Regulation provides a GTP framework for determining a price for sales gas produced as part of an integrated GTL project, to be included in a person's assessable receipts in respect of that project.[57]

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[51] This overview reflects the amendments most recently made to the PRRT Assessment Act which exclude onshore projects from the scope of the PRRT regime with effect from 1 July 2019: see the *Treasury Laws Amendment (2019 Petroleum Resource Rent Tax Reforms No. 1) Act 2019*.
[52] An offshore petroleum production licence relevantly means a petroleum production licence issued under the *Offshore Petroleum and Greenhouse Gas Storage Act 2006*.
[53] Section 22 PRRT Assessment Act.
[54] Section 2 PRRT Assessment Act.
[55] Definition of 'marketable petroleum commodity', definition of 'excluded commodity' and definition of 'assessable petroleum receipt' in subsection 2E(1), section 2 and paragraph 24(1)(e) PRRT Assessment Act.
[56] The PRRT Assessment Act also contemplates the circumstance where sales gas might be sold, just before liquefaction, in a non-arm's length transaction: paragraph 24(1)(d) PRRT Assessment Act; although this circumstance is not the primary focus of this Report, the same considerations apply to such a case involving the non-arm's sale of sales gas at the taxing point as the case where there is no sale of sales gas at the taxing point. Where such sales gas is sold in an arm's length transaction, the consideration receivable for the sale is its assessable value for PRRT purposes (paragraph 24(1)(b) PRRT Assessment Act) and the issue of determining an appropriate methodology to value the sales gas at the taxing point does not arise.
[57] Explanatory Statement to the 2005 Regulations (the '**Explanatory Statement**').

Specifically, the PRRT Regulation enables a price to be calculated where there is no sale (or no arm's length sale) of the sales gas that moves from the upstream stage to the downstream stage of the operation.[58]

Broadly, the PRRT Regulation provides three options for determining the amount of the assessable petroleum receipts for sales gas of an integrated operation at the taxing point, to be applied in the following order of priority:

- Advanced Pricing Arrangement (APA)[59] – a price (and associated methodology for its determination) agreed between the taxpayer and the ATO;
- Comparable Uncontrolled Price (CUP)[60] – a price that can be observed in the relevant market place for the sale of sales gas in an arm's length transaction and that is applicable to the particular project; and
- Residual Pricing Method (RPM)[61] – a price determined as the average of the cost-plus price calculated for the upstream stage and the netback price calculated for the downstream stage, as prescribed in the PRRT Regulation[62].

Specifically in relation to the CUP, the PRRT Regulation statutorily prescribes that:

- the CUP is a price for sales gas:
  - that was obtained for a sale in a market that the Commissioner is satisfied is a relevant market in relation to the transaction; and
  - that the Commissioner is satisfied is an observable arm's length price;[63] and
- in determining whether a market is relevant, the demand and supply characteristics of the market must be taken into account, which explicitly include but are not limited to:
  - the composition of sales gas sold in the market; and
  - geographic differences between the production facilities and the product delivery point of the sales gas sold in the market; and
  - the end functional use for the sales gas sold in the market (with examples prescribed including feedstock versus domestic end use);[64] and
- in determining whether a market is relevant, the following comparability factors must also be taken into account:
  - the terms of contracts usual in the market, including volumes, discounts, exchange exposures and all other relevant conditions that would reasonably be considered to affect the price;
  - market strategies;
  - the existence of spot sales (including market penetration sales) below or above marginal cost;
  - processing costs;
  - technology used in processing; and
  - any other factors that it would be reasonable to consider.[65]

[58] As above, the Explanatory Statement.
[59] Subsections 19(2) and 20(2) PRRT Regulation. See also section 23, PRRT Regulation.
[60] Subsections 19(3) – (4) and 20(3) – (4) PRRT Regulation. See also section 24, PRRT Regulation.
[61] Subsections 19(5) – (6) and 20(5) – (6) PRRT Regulation.
[62] Although the RPM is the option of last resort for offshore projects generally, the North West Shelf project is able to make an election to use the RPM in the absence of an APA (irrespective of whether or not there is a CUP): see subsection 20(5) and section 50 PRRT Regulation.
[63] Subsection 23(1) PRRT Regulation.
[64] Subsection 23(3) PRRT Regulation.
[65] Subsection 23(4) PRRT Regulation.

Appendix D: OECD Guidelines

Relevance to PRRT

The GTP framework set out in the PRRT Regulation is based on arm's length principles.[66] For the purposes of the PRRT Regulation, a transaction is defined to be non-arm's length if the Commissioner, having regard to any connection between the parties to the transaction or to any other relevant circumstances, is satisfied that the parties to the transactions are not dealing with each other at arm's length in relation to the transaction.[67] The definition is rather unhelpful and it leaves the term 'arm's length' open to interpretation. This formulation is, however, similar to that found in the former Division 13 of the *Income Tax Assessment 1936*.

Section 23 of the PRRT Regulation defines a CUP for the purposes of the PRRT Regulation as a price determined in a market that the Commissioner is satisfied is a relevant market, and that the Commissioner is satisfied is an observable arm's length price. Direction is given in subsections 23(3) and 23(4) about what factors must be taken into account in determining whether a market is relevant.[68] These regulatory factors provide a framework for consideration of a CUP, which may be seen to be a minimum requirement. Further guidance is not contained in the PRRT Regulation and therefore the OECD approach to CUPs may be considered to be the appropriate guidance material given its international acceptance as the basis for determining arm's length pricing between associated entities.

The authoritative nature of the OECD Guidelines for income tax purposes has been established through its pervasive and global use in related party matters in Australia and internationally, as a consensus based framework agreed by OECD member nations. Subdivision 815-B of the *Income Tax Assessment Act 1997* explicitly directs taxpayers to use these guidelines to determine arm's length prices. While the interpretation of the PRRT legislation ought to be discerned from the terms (including the text, context and purpose) of the legislation alone (as income tax law and, by implication, OECD guidance do not govern the interpretation of the PRRT law), its structure by comparison can highlight points of difference.[69] Further, the PRRT Regulation does explicitly reference internationally accepted transfer pricing principles.[70]

In addition, both State and Federal revenue authorities (by way of one example, in the context of State Royalty Projects) have relied, and continue to rely, on the OECD Guidelines for non-transfer pricing matters. Therefore, it appears reasonable to assume that in practice arm's length pricing methods, as recognised in ATO and OECD transfer pricing guidance, are relevant as points of reference or comparison in applying the arm's length principle for purposes of the PRRT Assessment Act and the associated PRRT Regulation. It can be reasonably concluded that observations obtained by using an appropriate arm's length pricing method in accordance with transfer pricing guidance, would provide a point of reference or comparison (if not a starting point) to assess the requirements in the PRRT Assessment Act and the associated PRRT Regulation.

Furthermore, Section B.1.8 of the Callaghan Review states that it would be appropriate to align the approach to establishing a CUP to the latest OECD recommendations and approaches on transfer pricing.

OECD Methods

The OECD Guidelines recognise five generally accepted arm's length pricing methods endorsed by the ATO:

- CUP method
- Resale Price ('**RP**') method
- Cost Plus ('**CP**') method
- Profit Split ('**PS**') method

[66] As above, the Explanatory Statement.
[67] Section 12, PRRT Regulation.
[68] Subsections 23(3)-(4), PRRT Regulation.
[69] *ZZGN* v Commissioner of Taxation [213] AATA 351 at paragraphs 248 to 250; Taxation Ruling TR 2014/9 at paragraphs 13 and 127.
[70] The Explanatory Statement: commentary on Regulation 19 of the 2005 Regulations (which is now Section 23 of the PRRT Regulation).

- Transaction Net Margin Method ('**TNMM**').

The OECD Guidelines state that where an alternate method (or combination of methods) gives a more appropriate arm's length outcome, that alternate method (or combination of methods) may be used. The focus of this Report is the CUP method as it relates to the application of the PRRT.

CUP

An arm's length price under the CUP method is determined by directly comparing the pricing of a controlled transaction with the pricing of a similar uncontrolled transaction between independent parties dealing at arm's length in comparable circumstances.[71]

An uncontrolled transaction is comparable to a controlled transaction (i.e. it is a comparable uncontrolled transaction) for the purposes of applying the CUP method if one of two conditions is met:

- a) none of the differences (if any) between the transactions being compared or between the enterprises undertaking those transactions could materially affect the price in the open market; or
- b) reasonably accurate adjustments can be made to eliminate the material effects of such differences.

Where it is possible to locate comparable uncontrolled transactions, the CUP method is the most direct and reliable way to apply the arm's length principle and is therefore preferable over all other methods.[72] The OECD Guidelines generally considers the CUP method to be the most appropriate method to apply to establish an arm's length price for the transfer of commodities between associated enterprises.[73]

Paragraph 2.20 in the OECD Guidelines provides useful direction on the economically relevant characteristics in order to assess comparability between the controlled and uncontrolled transaction:

> "For commodities, the economically relevant characteristics include, among others, the physical features and quality of the commodity; the contractual terms of the controlled transaction, such as volumes traded, period of the arrangements, the timing and terms of delivery, transportation, insurance, and foreign currency terms. For some commodities, certain economically relevant characteristics (e.g. prompt delivery) may lead to a premium or a discount...Where there are differences between the conditions of the controlled transaction and the conditions of the uncontrolled transactions or the conditions determining the quoted price for the commodity that materially affect the price of the commodity transactions being examined, reasonably accurate adjustments should be made to ensure that the economically relevant characteristics of the transactions are comparable. Contributions made in the form of functions performed, assets used and risks assumed by other entities in the supply chain should be compensated in accordance with the guidance provided in these Guidelines."

The five comparability factors are outlined below. To be considered comparable means that none of the differences between the situations being compared could materially affect the condition being examined in the methodology, or that reasonably accurate adjustments can be made to eliminate the effect of any such differences.[74]

Comparability Factors

The below background for each of the five comparability factors also references the relevant factors of the PRRT Regulation in brackets. The PRRT Regulation does not provide guidance as to the interpretation and application of the determinants to be considered when assessing the application of a CUP (referred to as 'demand and supply characteristics' and other 'factors'). However, the comparability factors outlined in the OECD Guidelines provide additional information and guidance to determine the existence of differences between a controlled and uncontrolled transaction and whether those differences materially affect the price. Given that the OECD Guidelines provide more information in order to determine whether an identified

[71] OECD Guidelines, paragraph 2.14.
[72] OECD Guidelines, paragraph 2.15.
[73] OECD Guidelines, paragraph 2.18.
[74] OECD Guidelines, paragraph 3.47.

transaction can be relied upon as a CUP, it is considered appropriate to consider the PRRT Regulations in conjunction with the OECD comparability factors.

Characteristics of property[75] (e.g. *composition of sales gas or natural gas*)

Depending on the transfer pricing method applied, this factor may be given more or less weight. The requirement for comparability of tangible property, such as a commodity, is the strictest for the CUP method when compared to applying other transfer pricing methods.

To assess the comparability of the characteristics of property involves determining whether the products transferred under the controlled and uncontrolled transactions are the same. For example, the identification of any differences that might have a material effect on price such as differences in quality, physical attributes, or functional features.

Specifically in the case of transfers of tangible property such as commodities, this may include the physical features of the property, its quality and reliability, and the availability and volume of supply.

Contract terms and conditions[76] (e.g. *terms of contracts usual in the market*)

This involves consideration of whether the material contractual terms governing both the controlled and uncontrolled transactions are comparable, including the form of consideration, sales volume, scope and terms of warranties provided, duration of the contract, credit and payment terms and incoterms.[77]

The contractual terms of arm's length transactions will generally define explicitly (or implicitly), how responsibilities, risks and benefits are to be divided between the parties. In transactions between independent parties, each party would ordinarily seek to hold each other to the terms of the contract, and contractual terms should / would only be modified if it is in both parties' interests, and after negotiation.

Economic conditions[78] (e.g. *geographic differences, end use, existence of spot sales*)

This involves consideration of whether the controlled and uncontrolled transactions involve comparable markets, in terms of geographic location, economic conditions, relative size, extent of competition, levels of supply and demand, the extent of government regulation, and the level at which the party operates in the relevant market (e.g. production, or wholesale or retail).

The existence of an economic, business or product cycle is another economic circumstance that may affect comparability. When comparing geographic markets, for a number of industries, large regional markets encompassing multiple countries may prove to be reasonably homogenous while for others, market differences may be very significant. As such, comparability of economic circumstances is also critical to method selection and application.

Business strategies[79] (e.g. *market strategies*)

This involves consideration of whether comparable business, pricing or marketing strategies affect both the controlled and uncontrolled transactions (e.g. a company in start-up phase might adopt differing pricing and marketing strategies to an established business). Business strategies may take into account many aspects of an enterprise such as innovation and new product development, degree of diversification, risk aversion, assessment of political changes, input of existing and planned labour laws, duration of arrangements, and any other factors bearing upon the parties' daily conduct of their business

Such business strategies must therefore be taken into account when determining the comparability of controlled and uncontrolled transactions.

Functions, assets and risks[80] (e.g. *technology used in process, other factors*)

In transactions between two independent parties, compensation will usually reflect the functions each enterprise performs, taking account of assets used and risks assumed. Applying this comparability factor therefore involves consideration of whether the contributions of the parties in both the controlled and

[75] OECD Guidelines, section D.1.3. See also section 23(3)(a), PRRT Regulation.
[76] OECD Guidelines, section D.1.1. See also section 23(4)(a), PRRT Regulation.
[77] "*A set of rules which* ***define*** *the responsibilities of sellers and buyers for the delivery of goods under sales contracts. They are published by the International Chamber of Commerce (ICC) and are widely used in commercial transactions.*" *Exporting FAQs | Expor.Gov | Export.*Gov (2018) Export.gov https://www.export.gov/export-faqs.
[78] OECD Guidelines, section D.1.4. See also sections 23(3)(b)-(c) and 23(4)(c), PRRT Regulation.
[79] OECD Guidelines, section D.1.5. See also section 23(4)(b), PRRT Regulation.
[80] OECD Guidelines, section D.1.2. See also section 23(4)(d)-(e), PRRT Regulation.

uncontrolled transactions are comparable, in terms of the economically significant functions performed, assets used and risks assumed (e.g. relative contributions to production, capital, marketing/advertising, distribution, transportation and warehousing functions, and risks associated with price, foreign exchange, etc.).

Examples of key functions may include design, manufacturing, assembling, R&D, servicing, purchasing, distribution, marketing, advertising, transportation, finance and management. The economic significance of all functions performed, in terms of their frequency, nature and value in the overall supply chain is critically important. This is echoed in the OECD's Actions 8-10 Reports and underpins the OECD's Base Erosion and Profit Shifting initiative – specifically the need to ensure transfer pricing outcomes are aligned with value creation (i.e. relative contributions of the parties to the value ultimately unlocked across the value chain).

The functional analyses should consider the type of assets used (e.g. plant and equipment, valuable intangibles, financial assets etc.) and the nature of those assets.

In terms of risks borne by the parties, the types of risks to consider include market risk, risk of loss associated with any investments, risks of success or failure of R&D activity, credit risk, foreign exchange risk etc. The parties' conduct will generally be taken as the best evidence of true allocations of risk. As part of the OECD's Actions 8-10 Reports[81], there was a particular focus on the capacity to bear, manage and control risk in substance. In an integrated GTL context where we are seeking to ensure that assessable receipts is accurately determined, the functional, asset and risk profiles of the parties is therefore highly important. It plays into method selection but also, for example, potential CUP adjustments (and of course is one of the 5 key comparability factors).

Conclusion

Evidently, the PRRT Regulation is more specific to the industry, however the factors still require a strict degree of comparability and it would be unlikely that one would identify a CUP under the PRRT Regulation when one would not under the OECD Guidelines. Therefore, applying the OECD Guidelines to determine the existence of CUPs comprehensively encompasses the requirements of the PRRT Regulation.

Adjustments

As noted above, to be comparable means that none of the differences between the situations being compared could materially affect the condition being examined in the methodology, or that reasonable adjustments can be made to eliminate the effect of any such differences.[82] Accordingly, in order to increase the reliability of results, comparability adjustments should be considered.

The OECD's Actions 8-10 Reports inserted specific additions to Chapter II of the Transfer Pricing Guidelines focusing on commodity transactions. This underlines the OECD's recognition of the complexities in achieving consistency in the transfer pricing of commodities. Importantly, it emphasizes that the characteristics that exist in commodity transactions are unique and thus more complex in determining a CUP.

Specifically, when it comes to commodity transactions, reasonably accurate comparability adjustments should be made, when needed, to ensure that the economically relevant characteristics of the controlled and uncontrolled transactions are sufficiently comparable.[83]

For commodities, the economically relevant characteristics include, among others, the physical features and quality of the commodity and the contractual terms of the controlled transaction such as volumes traded, period of the arrangements, the timing and terms of delivery, transportation, insurance and foreign currency terms. Relevant considerations in this regard include the materiality of the difference for which an adjustment is being considered, the quality of the data subject to adjustment, the purpose of the adjustment and the reliability of the approach used to make the adjustment. However, the need to perform numerous or substantial adjustments to key comparability factors may indicate that the third party transactions are in fact not sufficiently comparable.[84] This highlights the difficulty in determining reliable adjustments with third party transactions, particularly when approaches are so bespoke to each commodity arrangement and contract concluded.

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[81] Actions 8-10 Reports, page 51.
[82] OECD Guidelines, paragraph 3.47.
[83] OECD Guidelines, paragraph 2.20.
[84] OECD Guidelines, paragraph 3.51

Attachment 2

Wood Mackenzie

A Verisk Business

June, 2019

PRRT Review:
Review of the Residual Profit Split Methodology

2019 Review of Gas Transfer Price Methodology and Wood Mackenzie Scope

PRRT is a profits-based resource rent tax which taxes profits attributable to the petroleum resource at the point where a marketable petroleum commodity (MPC) is produced, once applicable costs and an agreed rate of return have been recovered. For the most part this point is the location where an observable sale takes place. In integrated LNG projects there is no observable sales price and a proxy gas transfer price needs to be generated as an enabler for PRRT calculations.

In the late 1990s the Government, following extensive consultation with industry and other stakeholders, introduced the Residual Pricing Method (RPM) to help address the issue of how to estimate gas feedstock value within integrated LNG projects and derive assessable PRRT receipts. The aim of the RPM was to establish an efficient and equitable mechanism to help a taxpayer calculate a 'fair and reasonable' gas transfer price reflective of an arm's length transaction where observable gas transfer prices do not exist (be it Advance Pricing Arrangements – APA, or Comparable Uncontrolled Prices - CUP).

Independent consultants Arthur Andersen were engaged at the time to help determine the most appropriate approach. They concluded that calculating the residual profit between the upstream and downstream phases of integrated LNG projects and then applying an equal (50:50) apportionment of these was "the most appropriate and potentially equitable solution" to generate a reflective feed gas transfer price and establish tax liabilities. Their recommendations were adopted by the Department of Industry, Science and Resources in 1999 and have formed the basis of PRRT gas transfer pricing calculations ever since.

In late 2018 the Government issued its final response to the Callaghan review of Petroleum Resource Rent Tax (PRRT). It requested a consultative review into the operation of the existing gas transfer pricing methodology (ie Residual Pricing Method - RPM) to ensure its 50:50 split remains fit for purpose and compatible with emerging developments in the industry .

Wood Mackenzie's contribution to this consultation exercise focuses solely on a discussion of the integrated LNG value chain, where value is created within it and how the LNG industry's evolution over the last 20 years may or may not have materially impacted the validity of 50:50 split solution under RPM.

Value creation and allocation across the LNG and the integrated LNG value chain

The LNG value chain is significantly more complex than a typical upstream gas value chain (eg pipeline gas). LNG projects require large, upfront investments in additional processing facilities (liquefaction), transportation and marketing activities to get the upstream gas to a point of sale. These accumulate significant additional costs and risks which need to be compensated so a project can pay back on its investment and generate profits.

Value is ordinarily created at every stage of the LNG process: from upstream production; to pipeline transportation; to processing and liquefaction; to shipping; to storage; to regasification; to distribution and finally sale to the consumer. Value may also be created from sales of gas from an integrated LNG project vehicle into the local domestic market. For resource taxation purposes we are most interested in the elements of the value chain up to the taxing point (for PRRT purposes that is the point where there is a marketable petroleum commodity).

Each of these links in the chain may be segmented (ie be owned by a different party or parties) or fully integrated (ie where the same party or parties own the entire chain). Segmented projects tend to apply arm's length agreements which determine transparent price realisation at each part of the chain. Vertically integrated projects generally do not have arm's length agreements between the difference stages and therefore may use proxy 'gas transfer' prices to determine economic rents or estimate respective pricing along the value chain. These can become important for taxation purposes where different tax treatments apply to different elements of the value chain, such as in Australian PRRT.

Australian LNG rents are subject to taxation at both PRRT and Federal Income Tax (FIT) level, with the PRRT ringfence extending to the upstream segment of the project (reflecting its design as a tax on super profits associated with the petroleum resource). The downstream and midstream elements of the LNG value chain (liquefaction, shipping and marketing etc.) do not fall under the ringfence of PRRT, and are instead captured by FIT at a different rate.

In vertically integrated projects the lack of observable pricing within the project vehicle means the sole revenue data point is the LNG point of sale. In other words, there is no observable transfer price at the point where risk and gas ownership are transferred from the upstream to the downstream element of the project. One way to administer taxes on integrated projects in line with PRRT legislation is to create a notional LNG gas feedstock ‘value’ at the upstream taxing point. The RPM and its profit split mechanism was designed to assist and simplify this process within integrated gas projects.

Estimating economic rent from some elements of the value chain is easier to determine than others, particularly where these elements can be cross referenced against comparable projects or assets. This may be the case for tangible assets such as production infrastructure. However, value generated from intangible assets such as differentiated LNG marketing efforts, LNG portfolio management and optimisation, project execution know-how or other intellectual property is more subjective, harder to quantify and even harder to verify.

In any case, such attempts to segment the risk and value drivers of different parts of the integrated LNG chain is conceptually flawed. Each element of an integrated LNG value chain is wholly interdependent - from the upstream wellhead to the LNG delivery point (be this FOB or DES). From a project perspective, gas would not be developed without the export infrastructure to process and sell it. Conversely this infrastructure would not be built without the development of the project vehicle’s ringfenced gas.

This point is underlined by the fact that integrated LNG projects are sanctioned as a whole, and final investment decisions (FID) are binary. This essentially confirms all risks and rewards are shared equally across the entire project vehicle from a project sponsor’s perspective.

This suggests that there should be a difference in how integrated and segmented upstream and downstream activities are considered for taxation purposes. Standalone upstream project revenues are largely generated through higher risk activities than downstream and may attract higher taxation through their potential to deliver higher profits and rates of return. Stand-alone downstream activities are often considered to generate infrastructure rates of return due to a perceived lower risk profile. If the risk profiles of the upstream and downstream in integrated projects are interdependent, an equitable split solution (such as the RPM 50:50) may in fact be the most appropriate. In short, while there may well be greater risks associated with different elements of the LNG value chain within that decision, these are absorbed and shared equally across the project and cannot be unpicked within an integrated project vehicle.

The ongoing validity of the RPM 50:50

The 50:50 split of the RPM was designed as the most equitable and practical solution possible at the time. That said, there are practical and conceptual challenges sometimes cited in respect of its application.

For example, as integrated LNG project owners control each segment of the value chain, there may be incentives to shift some economic rent beyond the upstream ringfence to reduce overall fiscal liabilities. Though in practice, this is unlikely to arise due to the role played by the ATO in audit and risk control activities. Likewise, the RPM’s fixed 50:50 split can draw criticism for its symmetrical treatment in both profit and loss-making situations. This relates to arguments that a higher portion of tax should be payable during periods of high prices, while the 50/50 split applies a 50% cap on attributable residual profits to both phases of an integrated project.

In many ways these criticisms are valid, albeit hard to remedy with a superior mechanism. The reality is the RPM is a conceptual solution and its split mechanism is to some extent subjective. As such it does not purport to calculate the actual allocation of economic rent between upstream and downstream in an integrated operation such as LNG, recognising that an exact split is difficult to ascertain. The RPM and its 50:50 profit splits were largely settled upon because it was viewed as the best option by the consultant engaged at the time, and adopted by government. The purpose of this review is to understand whether a different split mechanism could be adopted nowadays which would in some way be ‘better’.

Essentially the RPM tries to reconcile two conceptually different systems. On the one hand, a tax system built on the notion of separated upstream and downstream businesses collaborating through arm's length transactions. On the other hand, integrated projects where no distinction in ownership or interests exist between the upstream and downstream components. The RPM reconciles those systems by creating two notional upstream and downstream entities within the integrated projects. It then goes through three steps to determine the transfer price of gas within that mechanism:

1. Calculates an upstream cost-plus price representing the ex-ante minimum price at which the producer would be willing to sell the feed gas (capital costs plus operating costs plus a return on capital allowance – long term bond rate plus 7%);

2. Calculates a downstream netback price representing the ex-ante maximum price the downstream entity would be willing to pay for the feed gas (LNG sales minus capital costs minus operating costs minus a return on capital allowance - long term bond rate plus 7%);

3. Splits the residual profit (equal to netback price minus the cost-plus price) equally between upstream and downstream if the netback price exceeds the cost-plus price (i.e. if the project is profitable); or uses the netback price as the gas transfer price if the cost-plus price exceeds the netback price (i.e. if the project is loss-making).

Residual profit is determined as rents generated above an acceptable and normal economic return from either the upstream or downstream activity. A percentage uplift on capital employed (capital allowance) is applied to compensate for the financial, technical, marketing and operating risks that the activity incurs. The capital allocation and allowance rules can play a significant role in whether profit is generated in the first place. How capital is then allocated between upstream and downstream activities is critical to the determination of a price for PRRT purposes.

Profit allocation between upstream and downstream is a function of the balance of bargaining power between the two phases. The allocation of variations in gains and losses between the two parties reflects the ability that each counterparty has to either capture the gains for itself or push the losses to the other side.

Numerous soft elements determine this supplier/buyer bargaining power. These include; the relative supplier/ buyer concentration, the buyer's switching costs, the ease of vertical integration for either the buyer or supplier, the sensitivity to price of the buyer, the product differentiation of the supplier and the availability and cost of substitutes. The interplay and conversion of these qualitative elements into quantitative percentage splits is a judgement call and very difficult to do with any degree of rigour or consistency.

The gas transfer price derived from the RPM 50:50 split at best delivers a simplified and usable number which balances the position of all parties through the different phases. It does not take into consideration the dynamics of bargaining power between upstream and downstream through time, nor other factors that could shift value either upstream or downstream.

Therefore, the equal allocation of residual profit (50:50 split) between upstream and downstream was selected as the most appropriate solution when the RPM was adopted. This decision was largely taken in the absence of any better proposed solution, partly (but not entirely) due to a lack of precedence or prior experience of how to allocate profits in integrated LNG operations either in Australia or with relevant projects outside Australia, which we will explore now.

Australia’s LNG industry: then and now

The review asks whether anything resulting from the significant evolution of the global and Australian LNG industry since 1998, has fundamentally changed the ongoing validity of the RPM 50:50 split mechanism.

Ultimately, PRRT as a profits-based tax means its performance is heavily linked to commodity price volatility. As one might expect, prices have risen and fallen spectacularly over the period in line with commodity price cycles. Structurally, Australian LNG remains largely an oil-indexed, long-term contracted destined for Asian buyers, though price markers, mechanisms and indexation levels in contracts have evolved.

However, crucially the way LNG price is derived at the point of sale remains very similar and therefore offers us no additional insight into deriving proxy prices at the upstream ringfence. Likewise, while the absolute price of LNG and its value as a commodity is significantly higher now than in 1998, this consideration remains indifferent to the value allocation discussion.

Capital and operational costs have increased substantially both for upstream gas and downstream LNG. But again, it is unclear how the evolution of these cost patterns has diverged in terms of value allocation between upstream and downstream over the period and the implications this might have for the 50:50 split. During the last wave of Australian LNG build, plant costs on a per tonne basis ended up among the highest ever seen in the history of the industry due to cyclical cost inflationary pressures. These impacted the value and risk proposition of the downstream and called into question traditional perceptions over upstream and downstream project risks and where value is generated.

Looking forward there are arguments that the value allocation dynamics for a future set of Australian LNG projects could look very different. Brownfield or backfill projects should benefit from lower downstream costs due to the existing foundation infrastructure which now exists around Australia's coast. Likewise, the increasing complexity of extraction and remoteness of resources could feasibly drive up the cost of upstream gas.

But as the example of cost escalation in the last wave of Australian LNG shows, the external environment is variable, difficult to forecast and ultimately shifts value perceptions back and forth between upstream and downstream over any projected period. Australia high cost labor, often geographical remoteness of its infrastructure and extreme weather-related events will continue to impact the risk profile of future and existing downstream. And underutilised LNG capacity (both currently and threatened in the future) increase downstream unit costs.

As in 1998, the vast majority of Australia's upstream gas resources would not be developed without the infrastructure and market opportunity that LNG provides. The value-creating activities downstream (liquefaction, marketing and shipping of LNG) similarly require the development of upstream feed gas. This symbiotic relationship remains strong and presents little evidence for change on a circumstantial basis.

Similarly, forecasting the profitability and allocation of value of future Australian LNG projects remains as problematic as accurately calculating the bargaining power splits between upstream and downstream over a period of time.

Finally, as we have discussed, the RPM and profit split decisions have been conceptual solutions since inception and were not in any way linked to the state of industry in 1998, fledgling or otherwise. Therefore, the status and value drivers of industry today are unlikely to cast any more light on the fundamental challenge of allocating value to segments of an integrated project without observable prices at the taxing point.

Two decades of operational experience and data

Twenty years of the RPM's application has created significant experience of integrated LNG and its tax treatment in Australia. It has also generated large volumes of historical cost, production and pricing data across the LNG value chain from which the residual profits calculations can be analysed and benchmarked by project.

Nevertheless, the volume and quality of the 'cost plus' and 'netback minus' data really does not help us answer the key question over how to allocate value between the upstream and downstream from the residual profit. This is because there is still no magic formula that can accurately model the bargaining power between upstream and downstream within this residual profit. Arthur Andersen reached the same conclusion in 1998 when it stated that:

"in the context of establishing a gas transfer price between upstream and downstream operations it is difficult to determine a reliable mechanism for splitting the price based on the outcome of open market bargaining".

Alternative LNG taxation arrangements and arguments against fiscal change

Indeed, ensuring that the taxation of integrated LNG projects is more closely aligned to their fundamental structure and the guiding taxation principles of transparency and efficiency, would intuitively suggest a case for change exists in taxing integrated LNG project as a whole, not just a methodological change in how the residual profit element is split from within the RPM.

But any major fiscal overhaul would need to be prepared to overcome significant administrative, political and legal challenges. Australian upstream and downstream fiscal systems are well established and understood, and provide a stable basis for significant levels of investment. Any structural change in approach to integrated LNG taxation which negatively impacts project economics or increases administrative burden, could derail the progress to final investment decision of a number of new LNG projects in Australia.

This is because despite Australia's favourable resource and infrastructure position in global terms, no Australian LNG projects have been sanctioned since 2013. Projects in the USA, Canada, Russia, West Africa, Mozambique, Malaysia and Indonesia have all moved into development in the same period.

Uncertainty over future tax policy and its application tends to erode investors' confidence in a country, can impact investment flows and increase the cost of capital. It also damages productivity and efficiency through greater compliance costs for businesses to adapt to the changed approach. Worse, retrospective taxation (post-FID tax changes which change the economics of the initial business case) both hurts investors and creates a business environment favouring short-term investment thinking.

In any case a ringfenced integrated LNG tax could be equally as challenging to apply, particularly where LNG feed gas is supplied from different fields or indeed different or third-party producers. Likewise, recovery of sizeable downstream costs would likely only act to delay overall fiscal receipts for Government, compared to those realised much earlier from the upstream under PRRT. Perhaps more importantly, PRRT is designed to be a tax on super profits associated with the resource, not downstream value creation and would therefore not fit this model.

Conclusion

A tax system which differentiates between upstream and downstream is fundamentally challenged by the fact that integrated projects are developed as an interdependent whole. How much value sits within each ringfence is a judgement call and subject to variations over time.

A decision was taken in 1998 to clarify and amend the PRRT legislation through introduction of the RPM so that it could more clearly deal with integrated LNG projects. The RPM and its 50:50 profit splits ratio had theoretical and practical flaws, but constituted a workable solution to calculating proxy transfer prices in line with the PRRT legislation, where no arm's length transaction or local comparable benchmark exists.

Twenty years later, there is still no compelling actual or theoretical basis to determine how residual profits should be split under the RPM, that is in line with the guiding principle and objectives of the current PRRT legislation.

The only other theoretical approach which could more accurately account for and satisfy the objective and principle of the PRRT is a dynamic formula that could accurately encompass and articulate the drivers of profit allocation between upstream and downstream through time. However, such a formula cannot be accurately designed due to the fundamental difficulties of modelling the soft drivers of bargaining power between upstream and downstream. It would also be challenging to apply a single mechanism to all LNG projects given the inherent differences across Australia's LNG sector (conventional offshore, unconventional onshore, FLNG) or to feasibly manage multiple approaches to forecasting and validating gas transfer prices across different projects.

While the current mechanism may not be theoretically perfect there is also an argument that any drawn out fiscal instability caused by any major directional shift in taxation policy could see Australia miss its window of opportunity for progressing new LNG projects, during what is a critical timeframe for LNG project development. Gas may be the bridging fuel of the energy transition, but new technologies are emerging at a pace and scale which could ultimately threaten the long-term demand and value of Australia's considerable hydrocarbon resources.

In any case, a number of converging factors affect the structural and cyclical ability to generate PRRT aside from the residual profit split percentage . Under the existing mechanism future PRRT should rise through an increase in residual profit for allocation rather than shifting more of the value to upstream within the residual profit band. As costs continue to be recovered these LNG projects should become more profitable, and generate higher PRRT particularly in high commodity price environments.

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