



Australian Government
The Treasury



Petroleum Resource Rent Tax: Review of Gas Transfer Pricing Arrangements

Final report to the Treasurer

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1. Preface

1.1 Background

On 2 November 2018, the former Government announced its final response to the Petroleum Resource Rent Tax (PRRT) Review conducted by Michael Callaghan AM PSM (the Callaghan Review).

The Callaghan Review made a number of observations and recommendations regarding the overall operation of the PRRT. It also identified concerns over whether the outcomes of the gas transfer pricing (GTP) Regulation¹ ensures that the Australian community is receiving an equitable share from the gas used in liquefied natural gas (LNG) projects. The Callaghan Review recommended that the GTP Regulation be examined to identify possible 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.

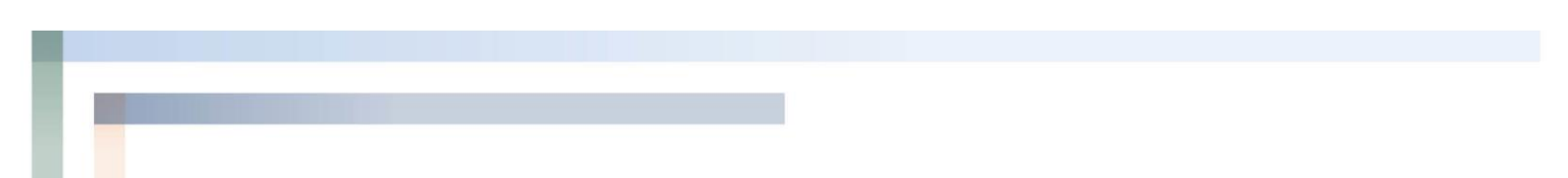
As part of its response to the Callaghan Review, the former Government asked Treasury to lead a review of the GTP Regulation, which determines the value of gas for PRRT purposes in integrated LNG projects. On 5 April 2019, the former Assistant Treasurer, the Hon Stuart Robert MP, tasked Treasury to provide advice 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 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 as neutral 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.

The GTP Review was paused in early 2020, as Treasury's resources were redeployed to focus on the Covid-19 pandemic. Treasury resumed the Review in December 2022.

There have been significant developments in global energy markets and local energy demand since the commencement of the Review, including the increasing importance of gas in supporting the transition to low-emissions energy generation and the changing role of LNG in supplying gas to Western Australia and the Northern Territory. The Government has introduced a number of reforms to support this transition, consistent with many companies' plans to achieve net zero emissions, while also ensuring affordability and certainty of energy for households and businesses.

¹ Throughout this report, a reference to 'GTP Regulation', 'GTP rules', or 'GTP arrangements' is a reference to the *Petroleum Resource Rent Tax Assessment Regulation 2015*.



Given these developments, and the Callaghan Review finding that ‘a change to the transfer pricing arrangements could have major implications for existing projects’, Treasury has considered alternative approaches consistent with the overall intent of the PRRT to ensure the Australian community receives an equitable return for the extraction of its oil and gas resources, while not discouraging investment in exploration and development in the industry.

1.2 Recommendations

Recommendation 1: Treasury considers that the existing GTP Regulation results in a structural undervaluation of gas at the PRRT taxing point for integrated LNG projects, particularly when resource prices are high.

Modifying the existing ‘safe harbour’ transfer pricing method – the ‘Residual Pricing Method’ (RPM) – to ensure gas is more fairly priced at the PRRT taxing point for integrated LNG projects would address this under-valuation and could be implemented in one of two ways.

Recommendation 1a. The RPM could be replaced with a ‘Netback only’ method. The rate of return that is provided to downstream assets in this case should be maintained at the current Long Term Bond Rate plus 7 percentage points (LTBR+7) with an additional allowance of LTBR+7 on operating expenditure in the year it is incurred.

Recommendation 1b. Alternatively, the existing safe harbour pricing method – the RPM – could be modified to provide a profit split weighted 80:20 to the notional upstream entity with an additional allowance of LTBR+7 on operating expenditure in the year it is incurred.

Treasury considers addressing the under-valuation of the resource via the Netback only is likely to raise the overall tax burden on new projects such that it increases risks for future investment in new and existing projects. The modified profit split reduces this risk by recognising that some of the rent is attributable to downstream operations. However, the PRRT has been found to be better suited to oil projects rather than LNG projects since the accumulation of a large stock of carry forward deductions, compounded by uplifting, can defer the payment of PRRT indefinitely. Changes to the RPM alone would not effectively address this issue for LNG projects.

Treasury considers that a cap on the use of deductions to offset assessable income earned by LNG producers under the PRRT could be introduced as an alternative to changing the profit split ratio. This would bring forward PRRT receipts from LNG projects which are yet to pay PRRT and ensure a minimum return to taxpayers from the offshore LNG industry, while further limiting negative impacts on investment incentives and risks to future supply. This would be an adaptation of the PRRT’s function as a rent tax, to account for the particular economics of LNG projects, by incorporating a minimum payment linked to project revenues.

Recommendation 1c. Limit deductible expenditure to the value of 90 per cent of PRRT assessable receipts in respect of each project in the relevant income year (applied after mandatory transfers of exploration expenditure). Unused denied deductions would be carried forward and uplifted at the Government long-term bond rate (LTBR).

This option would only apply to projects that produce LNG. To minimise the impacts of upfront payments on project economics, projects would not be subject to the cap until 7 years after first production. The cap would not apply to certain classes of deductible expenditure in the PRRT: closing-down expenditure, starting base expenditure and resource tax expenditure.

To complement the different options under this recommendation, Treasury makes the following recommendations for the GTP Regulation to better reflect the contributions and risks of the notional entities that comprise the LNG value chain:

Recommendation 2: if a Netback only approach is adopted (Recommendation 1 refers), reduce the augmentation rate for the construction and pre-production time periods to the general PRRT augmentation rate to reflect that the methodology should not compensate investors with commercial rates of return on assets during the pre-earnings phase.

Recommendation 3: Require projects to make an irrevocable election to use the shorter or longer asset life formula to remove the integrity risk that projects change the operating life of capital projects to benefit from higher rates of return allowable under the shorter asset life formula.

Recommendation 4: If the RPM is retained, include appropriate exploration and development costs in the upstream cost base, with an appropriate way of bringing very old expenditure to current values. This could be achieved by applying the GDP deflator to original expenditure.

Recommendation 5: If the RPM is retained, equalise the treatment of the notional upstream and downstream entities between loss situations and profit situations.

Treasury also makes the following recommendations about other aspects of the GTP Regulation:

Recommendation 6: Update the comparable uncontrolled price (CUP) rules to align with the OECD guidelines. In particular, the analysis for the CUP should be broadened to consider all reasonable conditions of a comparable transaction. Reasonably accurate adjustments would continue to be permitted.

Recommendation 7: Modify the Advance Pricing Arrangement (APA) rules to provide guidance to industry and the Commissioner of Taxation on the principles that the Commissioner must have regard to in agreeing an APA. If the RPM is retained, then the use of an APA should be limited to circumstances where it is required to give practical effect to the statutory residual profit split.

Update regulatory treatment of tolling and backfill arrangements

Treasury is also making recommendations to modernise the regulations for emerging developments in LNG project structures. Treasury considers that the current arrangements may lead to widely different tax outcomes depending on how a project is developed, potentially leading to distortions in how decisions are made and what projects are sanctioned.

Recommendation 8: Update the regulations for tolling arrangements to support the effective operation of the RPM and to ensure that arm's length/commercial transactions for parts of the LNG production chain (that reflect the underlying resource ownership and risks to parties) are used as far as possible as a reference for establishing a gas transfer price.

Recommendation 9: Update both the PRRT general anti-avoidance rule and the arm's length rule to clarify that they apply to the GTP Regulation. This follows a recommendation made by the Callaghan Review that the Government amend the PRRT anti-avoidance rules to be in line with the income tax anti-avoidance rules.

Recommendation 10: The project combination rules should be revisited with a view to strengthening the requirement that the new field have some relevant geological or geochemical connection to the existing project.

Recommendation 11: Update the GTP Regulation to ensure that where an LNG facility enters the PRRT regime (either solely for the purposes of the GTP Regulation or for broader PRRT calculations) for the first time for backfill or tolling purposes, the value of the plant for use in PRRT calculations is the historical cost of the LNG facility, uplifted by the GDP deflator to the date of first production for PRRT purposes.

Date of application

Treasury recommends that the proposed changes apply to all LNG projects subject to the PRRT, as soon as is practical, recognising that more detailed design of new law will be required.

The current Regulation is due to sunset on 1 April 2026 and while it must be remade by that date, new rules could be developed to enter into force ahead of that time. The deficiencies identified in the current rules, and the period they have been in force, suggests it would be appropriate to apply any changes to existing projects going forward.

1.3 Consultation process

Treasury has undertaken a substantial consultation process.

Treasury hosted a first roundtable with industry participants in January 2019, followed by the release of a public consultation paper in April 2019.

The 2019 Consultation Paper outlined the operation of the existing GTP Regulation and laid out several key issues for consideration, including existing CUP and RPM methodologies, tolling arrangements in the industry and APAs. 21 submissions were received from the community, civil society groups, academics and industry in response, including four confidential submissions.

Between December 2019 and February 2020, Treasury conducted a round of targeted and confidential consultations with industry on a refined set of GTP reform options. This consisted of a second industry roundtable, meetings with individual firms and a further round of written submissions to Treasury. In April 2020, the GTP Review was paused to allow Treasury to divert resources to supporting the former Government's response to the COVID-19 pandemic.

The Review recommenced in December 2022. Industry roundtables were held in December 2022 and March 2023, accompanied by further targeted consultations with individual firms. Treasury also undertook consultation with independent industry analysts and representatives from State and Territory Governments, to examine proposed reforms to the GTP regulation in the context of broader industry, regulatory and economic considerations.

Much of Treasury's consultation has occurred on a confidential basis to facilitate frank and constructive discussions about the impact of proposed changes on current and future investments.

Over the course of Treasury's Review, the information and views put forward by industry have been highly valuable in developing Treasury's understanding of operational issues associated with the current GTP Regulation and testing possible reforms needed to address issues identified by Treasury.

2. Executive summary

The Petroleum Resource Rent Tax (PRRT) is a tax on oil and gas projects located offshore in Australian waters. Onshore oil and gas projects pay royalties to state and territory governments instead. In 2020-21, out of a total of 33 PRRT projects, 10 entities paid PRRT in relation to 6 PRRT projects.²

PRRT is a profits-based tax that only taxes profits of petroleum projects above a specified rate of return. Whether a project pays PRRT will be dependent on a range of factors, including commodity prices, foreign exchange rates and project development and operating costs.

PRRT is paid when a petroleum project's total assessable receipts exceed total deductible expenditure. The point at which petroleum, or products produced from petroleum, becomes taxable is commonly referred to as the taxing point. The taxing point signifies the boundary between petroleum project operations, which fall within PRRT, and non-project operations, which do not.

The gas transfer pricing (GTP) Regulation is used to determine the value of sales gas (feedstock natural gas) used to produce LNG at the taxing point in integrated Liquefied Natural Gas (LNG) projects, from which the assessable receipts of the petroleum project are calculated.

The efficacy of the GTP Regulation was a significant focus for the 'Callaghan Review' into the PRRT. The concerns identified regarding the credibility of the GTP Regulation and its significance in determining PRRT outcomes for integrated LNG projects prompted the former Government to establish this Review as part of its formal response.

The Callaghan Review identified that the RPM likely significantly undervalues gas prices for PRRT purposes because of the way capital is allocated, augmented (via the capital allowance rate) and rewarded (via the profit split). This reduces the assessable receipts of integrated LNG projects, and PRRT collected from them.

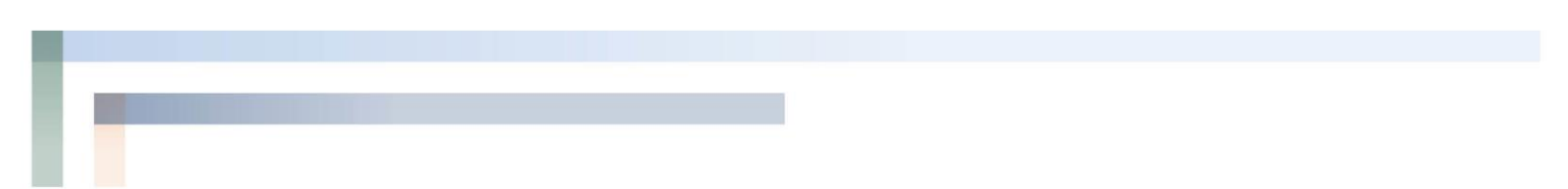
The fact that Australia is now the world's largest exporter of LNG underscores the increasing significance of the Callaghan Review's finding, and thus the central premise of this Review: to advise on options for ensuring the PRRT's application to integrated LNG projects is fit-for-purpose into the future.

A transfer or 'sales' price must be determined by the GTP Regulation because the PRRT applies to profits generated from the sale of 'marketable petroleum commodities' (MPCs) produced or extracted from a reservoir. However, unlike natural gas sold to the domestic market through the conventional pipeline network, there is no arm's length sale in integrated LNG operations at the PRRT taxing point, which is the point where the natural gas has been processed and is ready to be converted into LNG.

The GTP Regulation has a significant influence on the overall PRRT revenue collected on behalf of the Australian community for the recovery of its offshore gas resources. If the settings for the primary method used for pricing sales gas are not balanced and appropriate, it can extend the time before a project pays off its deductible (and typically large) investment costs and thus becomes profitable for PRRT purposes. Relative to oil projects, there is already a substantial delay before LNG projects start paying PRRT, owing to longer and more costly development cycles that can lead to high compounding of carry-forward deductions.

Upon close examination, Treasury considers that the existing safe harbour pricing method in the GTP Regulation, the 'residual pricing method' (RPM), is configured in a way that undervalues the underlying natural resource used in LNG projects. The central issue is that under the RPM, too much of

² <https://www.ato.gov.au> and, Taxation statistics 2019–20 Table 5: GST and other taxes – Petroleum resource rent tax, Selected items: 1999–2000 to 2020–21 financial years.



the economic rent generated from gas extraction is attributed to the downstream operations of the LNG value chain, where it is outside of the PRRT tax calculation. This is primarily because the original co-designed RPM was built on an assumption that the economic rents were equally split between the upstream and downstream parts of the integrated project. The result of this undervaluation of the economic rents in the underlying resource is that PRRT receipts collected on behalf of the Australian community from LNG projects are both delayed and significantly less than should be the case.

Treasury analysis concludes that economic rents, to the extent that they exist in projects, derive largely from the underlying gas resource (upstream). While rents may exist in the downstream in some projects at times, they likely do not exist in every project or for the life of every project.

Downstream processes and management of the associated risks may capture economic rents in some circumstances, but those same downstream processes can erode project rents through construction cost overruns, which has occurred in most Australian LNG projects. The risks associated with notional downstream ownership can be accounted for via a commercial risk-adjusted return in the PRRT, rather than a share in the excess profits. Put another way, the management of risk is not a contribution that generates economic rents. Treasury considers that integration, shared assumption of risks and value-add at every stage should generally be rewarded by a consistent commercial risk-weighted rate of return on the project rather than a residual profit split.

Industry argues the downstream in integrated projects deserves more than a commercial return because these projects are also interdependent: without the downstream there is no access to foreign markets (and higher international prices), and so residual profits should be shared equally. Industry's view is that the liquefaction plant and associated engineering and intellectual property (IP) know-how are also unique and valuable assets that create value beyond a normal commercial return. They maintain that the risks associated with marketing and selling LNG are significant and the downstream business deserves more than an infrastructure owner/utility provider commercial return.

Treasury has formed the view that while aspects of industry arguments about economic rents in the downstream are acknowledged, a 50:50 residual profit split attributes too much rent to the downstream contribution. The role of the residual profit method is to identify the source of the residual (excess) profits. While the downstream may contribute to the generation of economic rents in some circumstances, a key finding is that the RPM does not include the value of the resource as an upstream input cost. The attribution of economic rents should therefore be weighted more towards the upstream process.

Absent other factors, Treasury recommends that the GTP Regulation be modified to attribute more of the economic rents to the resource. This could be achieved in one of two ways. The first option is to replace the RPM with a netback only pricing method. The netback only methodology is already a component part of the existing RPM and is widely used in taxation and commercial settings for resource valuation in a value chain where there is no commercial transaction. This approach would attribute all of the residual profits to the upstream, consistent with the view that the source of economic rents is in the underlying resource and that downstream operations of the LNG value chain do not consistently generate rents in all projects. If the netback only method was to be adopted, the existing 'Advance Pricing Arrangement' (APA) method would remain the avenue for companies where they can demonstrate that economic rent is created by downstream operations. This would allow projects to enter into bespoke arrangements that reflect their particular circumstances.

The other option is to modify the RPM by adjusting the existing profit split between the upstream and downstream parts of the integrated project. This adjustment would attribute a smaller allocation of residual profits to the untaxed downstream operations in all projects, reflecting the view that while the primary source of economic rents is in the underlying resource, an inconsistent level of economic rents may be generated for some projects in their downstream activities.

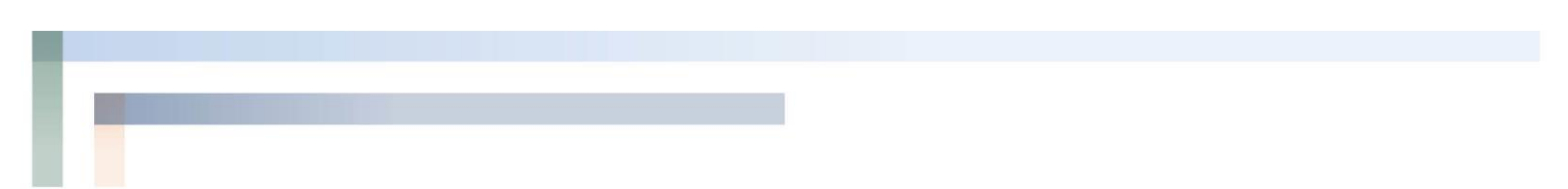
While both options would potentially raise the overall level of PRRT liabilities over the life of some projects and reduce project returns to investors, the revised RPM would also have a less detrimental effect on new project investment decisions and provide greater certainty to industry as a safe harbour. It would avoid the need for complex and time-consuming APAs to be negotiated with the Commissioner of Taxation.

The Callaghan Review estimated that changing the GTP Regulation to a netback only approach would result in an additional \$89 billion to 2050. However, variations in oil prices which most LNG contracts are linked to, higher construction costs, and continued compounding of deductions since the modelling undertaken by the Callaghan Review mean that similar policy changes outlined in this Review would not have as significant an impact as previously forecast.

Structural changes to the GTP Regulation would be expected to lift overall PRRT revenue collections under a range of oil price assumptions. Using an oil price assumption of US\$72.70 West Texas Intermediate indexed by CPI beyond 2026-27, Treasury analysis estimates that changing the RPM to a netback only method, in concert with several complementary changes to the RPM calculation, could result in an increase in PRRT receipts of around \$4 billion over the period to 2033-34 and around \$16 billion over the period to 2049-50 for existing LNG projects. Modifying the RPM to an 80:20 profit split could increase PRRT receipts by over \$2 billion over the period to 2033-34 and around \$10 billion in total over the period to 2049-50. It is important to emphasise that such estimates are not forecasts, as PRRT revenue is highly dependent on the future path of oil and gas prices which is highly uncertain. These estimates are not the equivalent of budget costings as they do not, for example, take into account other interactions with the tax system.

Treasury also recommends clarifying the PRRT settings and GTP Regulation for 'tolling' and 'backfill' arrangements. Tolling describes an infrastructure owner's provision of liquefaction or other infrastructure services for a third-party resource owner. While the majority of Australia's existing LNG projects that are subject to PRRT are fully integrated, it is likely that infrastructure and resource ownership will increasingly be separated as the LNG industry matures. Industry has indicated that tolling arrangements will become more prevalent in the future to facilitate the processing of new gas fields while minimising the construction of new downstream infrastructure and ensuring existing liquefaction infrastructure remains utilised.

Another consideration is ensuring that resource owners who develop new fields using their own infrastructure are not advantaged by the existing tax arrangements compared with tolling arrangements. New discrete fields should face similar tax arrangements regardless of whether they use a tolling model or are otherwise incorporated into project infrastructure. The PRRT is a project-based tax and losses, except for exploration, are not transferable from unprofitable to profitable projects. Treasury recommends consultation with the broader oil and gas industry to establish whether the project combination rules be revisited with a view to strengthening the requirement for new resources to be treated as separate projects. In the LNG context this may be necessary to stop losses associated with one production licence and associated infrastructure from being able to be offset against revenue from another field. The introduction of a deductions cap (discussed below) would also limit the use of such deductions. The effect of combination certificate rules has become a more significant issue with the emergence of the LNG industry given the increased potential for project losses to compound indefinitely, thus shielding future projects from PRRT liabilities.



In making any changes to the project combination rules, consideration should be given to several practical and administrative difficulties that industry participants have submitted would exist if projects could not combine.³

This Review consulted extensively with LNG industry participants and other interested parties over several years and processes, beginning with the Callaghan Review. Industry has largely maintained its position that no changes should be made to the existing GTP rules, arguing that the PRRT is operating as intended in its application to LNG and that current settings are the best fit for future LNG developments involving brownfield expansion and backfill projects. Industry highlighted that the current GTP rules, which resulted from a co-design process between government and industry participants that ran from the mid-1990s to the early 2000s, remain fit for purpose, as do the principles and assumptions that underpinned them. Some industry participants submit that although some projects will never pay PRRT under existing settings, even with high LNG prices, the collections from corporate income tax (which has a more significant impact on investment decisions) as well as the jobs and other economic spill-over effects associated with LNG projects represent an appropriate return to the community for the use of Australia's gas resources where PRRT is not payable. Industry noted that hurdle rates of return for project investment decisions are above current PRRT uplift rates and that changes to tax settings that increased the likelihood of tax being payable would risk future investment.

Submissions from others in the community, including academics, civil society groups and policy bodies, generally considered that reforms to the GTP Regulation are needed to secure a fairer return to the community. The Tax Justice Network, Uniting Church in Australia (Synod of Victoria and Tasmania), The Australia Institute and the International Transport Workers Federation, each advocated for a netback only approach to pricing the value of sales gas used to produce LNG for current and future gas projects. They consider that a netback only approach would achieve greater simplicity, transparency, and fairness in the operation of the PRRT.

The recommendation to amend the GTP Regulation, either by moving to a netback only method or modifying the profit split in the RPM, is designed to address the structural undervaluation of gas at the PRRT taxing point for integrated LNG projects and give the community confidence that the PRRT is fit for purpose for the LNG industry moving forward. However, Treasury acknowledges that this may not increase revenue from existing LNG projects in the medium term. Indeed, some projects may not be sufficiently profitable to pay any PRRT over their project lives in the event of sustained lower LNG prices, regardless of the recommended change. In such circumstances, Australians will continue to forgo any return attributable to their ownership of the recovered gas.⁴

Treasury has also considered the significant impact of modifications to the GTP rules, alongside other changes affecting the industry which may impact the economics of current and future LNG projects.

In light of these considerations, Treasury canvassed a change to the PRRT design outside of the GTP arrangements with industry participants, involving a cap on the use of carry-forward deductible expenditure to the value of 90 per cent of assessable PRRT receipts in respect of each project. This would bring forward PRRT revenue from existing projects, providing a timely and minimum return through PRRT revenue from Australia's offshore LNG industry.

A deduction cap would begin generating PRRT receipts immediately and, at the oil price assumption described above, would raise around \$7 billion in PRRT receipts over the period to 2033-34.

³ The practical and administrative difficulties submitted by industry are outlined in Part 7.2 of this Review that discusses combination of PRRT Projects.

⁴ The Australian community may nonetheless benefit from company tax payments, jobs and energy supply otherwise provided by such projects.

Recognising that the deductions cap operates as a bring forward of PRRT with denied deductions uplifted at LTBR, it is estimated to increase PRRT receipts by around \$3½ billion over the whole period to 2049-50. As noted above, these estimates are not the equivalent of budget costings.

Treasury acknowledges that recommendations which increase the overall tax burden on projects also lower the internal rate of return (IRR) to investors. This could affect future investment decisions and may mean that some marginal investments are less likely to proceed, particularly if the after-tax return on an investment is less than or close to the hurdle rate set by investors. However, the PRRT tax settings should be designed to balance a fair return for the community for the use of its natural resources with returns to investors.

Some industry participants have shown Treasury, on a confidential basis, high level modelling impacts for both the netback only option and the modified RPM option, on their sanctioned and potential future projects that show the effect of proposed changes move some of the projects from being investment grade to non-investment grade. Treasury has not been able to independently verify these claims.

Independent industry analysts supported the view that, to the extent changes to the PRRT brought forward and/or increased expected PRRT payments, Australia would become a relatively less attractive country for investment compared to other destinations. Further, PRRT changes would be coming on top of other policy changes. Analysts observed that, taken cumulatively, these changes are creating some uncertainty in the investment climate. However, already sanctioned projects would still be likely to proceed.

Independent industry analysts also noted, while tax is an important consideration for company decisions regarding new investments, there are many other factors that influence final investment decisions. These include uncertainty over project development costs, volatility in oil and gas prices, compliance with environmental and market regulations, global demand for gas through the energy transition and effect of take-up of alternative technologies. It was also noted that any additional impact on the investment climate for the LNG industry needs to be balanced against the fact that the PRRT is not seen as delivering for the Australian community.

Treasury's assessment is that the recommendations, if implemented, will not on their own determine whether any new investment decision proceeds or not. There are other more important factors that determine whether a project provides sufficient returns to invest, the most important being the price of and demand for the project's gas.

Treasury has suggested changes (Netback only or modified RPM) that are consistent with the design of the PRRT as a project-based tax that allows a return to investment before PRRT is payable, that does not tax the 'value add' of the downstream functions and ensures that resulting profits are taxed at the PRRT tax rate. Treasury has also suggested an alternative change (deductions cap), which would be an adaptation of the PRRT's function as a rent tax, as a way of bringing forward PRRT revenue and ensuring a minimum return to the Australian community from the offshore LNG industry.

Treasury considers the proposed changes should apply to all projects as soon as is practical, subject to detailed design of new law.

3. The gas transfer pricing rules

3.1 Overview

The purpose of the gas transfer pricing (GTP) rules is to determine the price of feedstock natural gas (sales gas) used to produce LNG which, in turn, is used to calculate PRRT revenue from an LNG project.⁵ A transfer price must be determined because, unlike natural gas sold to the domestic market through the conventional pipeline network, there is no arm's length sale in integrated operations that convert natural gas into LNG.

The LNG sale price is not used to calculate a PRRT liability because PRRT applies to profits generated from the sale of 'marketable petroleum commodities' (MPC) produced or extracted from a reservoir. In the context of this Review, the relevant commodity is sales gas, which has been processed to remove liquid petroleum gas, condensate, and carbon dioxide, whereas LNG is a downstream product made from sales gas. Thus, the applicable input for determining a PRRT liability is the sales gas price, rather than the LNG price.

The GTP Regulation was originally introduced in 2005 involving a co-design process with the industry and involving an independent report by former accounting firm, Arthur Andersen, the background of which is set out further below.

3.2 Background

Overview and historical context of the PRRT

The PRRT is a profit-based tax which aims to tax the economic rents in a petroleum project. As a rent tax it seeks to tax the returns to investors after a normal rate of return with the aim of minimising any distortion of investment decisions. Unlike other resource taxation mechanisms such as production-based royalties or excises, the PRRT is intended to emulate the tax neutrality benefits, but not the revenue risks, of cash-flow taxation. That is, the PRRT taxes annual positive cash flow, but does not provide general cash rebates for annual tax losses. Instead, tax losses are carried forward and uplifted (or augmented) annually to preserve their value and offset against any future positive cash flow of projects.

The PRRT was introduced in 1987 when development of petroleum resources was largely focused on oil rather than gas. Its policy design reflects key characteristics of petroleum resource development, namely that it carries high levels of risk for firms, but also the prospect of high reward in the form of economic rents attributable to the resource. Key features of the PRRT that reflect the principles of economic rent taxation include immediate deductibility of capital and revenue expenditure, carry-forward and uplifting of undeducted expenditure and refundability of PRRT previously paid for costs incurred when a project is closed.

The pronounced shift away from oil and domestic gas projects in favour of large-scale LNG projects over the last two decades has important implications for the PRRT. LNG projects have very different PRRT profiles as a result of different project structures, lifecycles, and levels of capital expenditure. For instance, LNG projects are highly capital intensive and, compared to oil projects, generally take much longer to become cash flow positive after commencing production.

⁵ It is also relevant to the determination of a PRRT liability for gas-to-electricity projects.

This has flow-on effects in terms of assessable PRRT revenue, particularly where firms have very large carry-forward deductions that are uplifted for years, sometimes decades, allowing excessive compounding to occur.

Development of the Gas Transfer Price methodology

The major expansion of the Australian LNG industry began in the 2000s, following expectations of growing international demand for gas. This made the significant discoveries of gas fields in remote Commonwealth waters, among others, economic to exploit. By default, offshore projects are subject to PRRT but, at the time, there was uncertainty as to how PRRT would apply given the relevant MPC is sales gas and not LNG.⁶

In the late 1990s, the Government worked with industry to agree on a set of principles for determining a way to price the sales gas used in LNG operations, which comprised the following:

- Only upstream activities (extraction and processing to sales gas) would be liable for PRRT
- Outcomes should be assessed against economic efficiency criteria
- GTP methodology should apply to all integrated LNG projects⁷
- Project risks should be equitably reflected on all cost centres
- The transfer price should reference the first commercial third-party price for derivative products
- The transfer price should be transparent, equitable, auditable, and simple to administer.

The Government commissioned a report⁸ from the former accounting firm, Arthur Andersen, in 1998 to perform an analysis of the LNG industry and recommend a methodology that would determine the price that would be arrived at in otherwise arm's length commercial negotiations and consistent with the agreed principles set out above.

This process resulted in the adoption of the following three methods for calculating the gas transfer price:

Method 1 Comparable Uncontrolled Price (CUP) – The CUP is a shadow pricing method in which the transfer price is determined by finding a comparable 'uncontrolled' transaction in similar circumstances.

While this method is considered best practice, when it is available, there are no CUPs currently used as there are no observable sales at the taxing point, which is usually within the liquefaction plant. It is unlikely a CUP will arise in the foreseeable future unless there are significant changes to the way that LNG projects are structured.

Method 2 Advance Pricing Arrangement (APA) – This method is based on agreement between the Commissioner of Taxation and a taxpayer for calculating an arm's length price. It provides flexibility to consider any specific (or possibly unique) facts and circumstances of a particular taxpayer.

⁶ Although the North West Shelf project had been exporting LNG to Japan since 1989, it was not subject to the PRRT given its pre-existing royalty arrangements.

⁷ It was also to apply to all integrated gas-to-electricity projects.

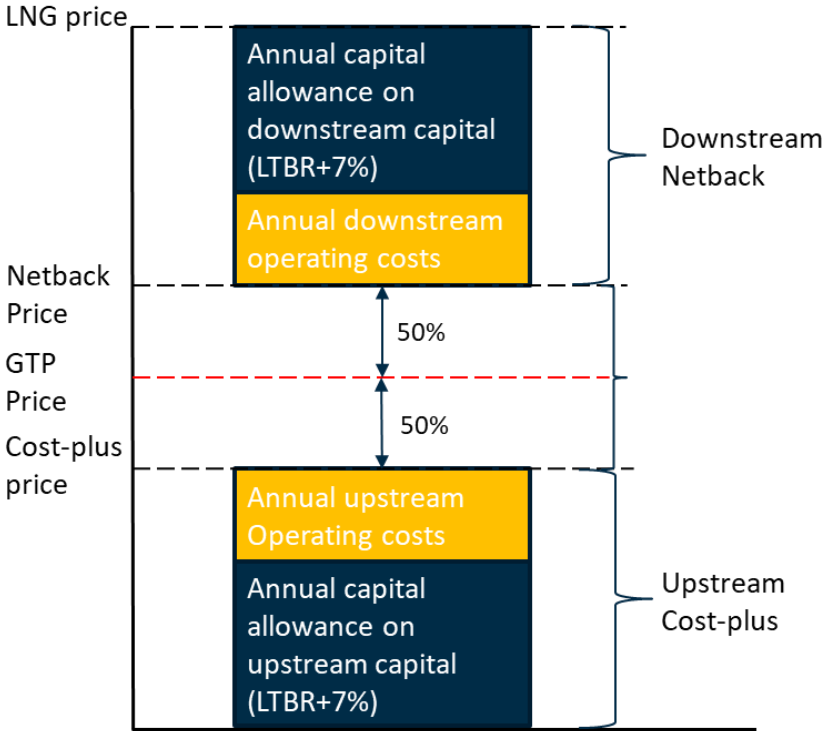
⁸ Report available at [Petroleum Resource R...~https://treasury.gov.au/consultation/c2019-t364690](https://treasury.gov.au/consultation/c2019-t364690).

Method 3 Residual Pricing Method (RPM) – This method is based on a hypothetical bargaining position reached between a notional upstream entity (the PRRT project) that sells sales gas to a notional downstream entity (liquefaction plant, marketing, and shipping; all outside the PRRT tax net) at the taxing point.

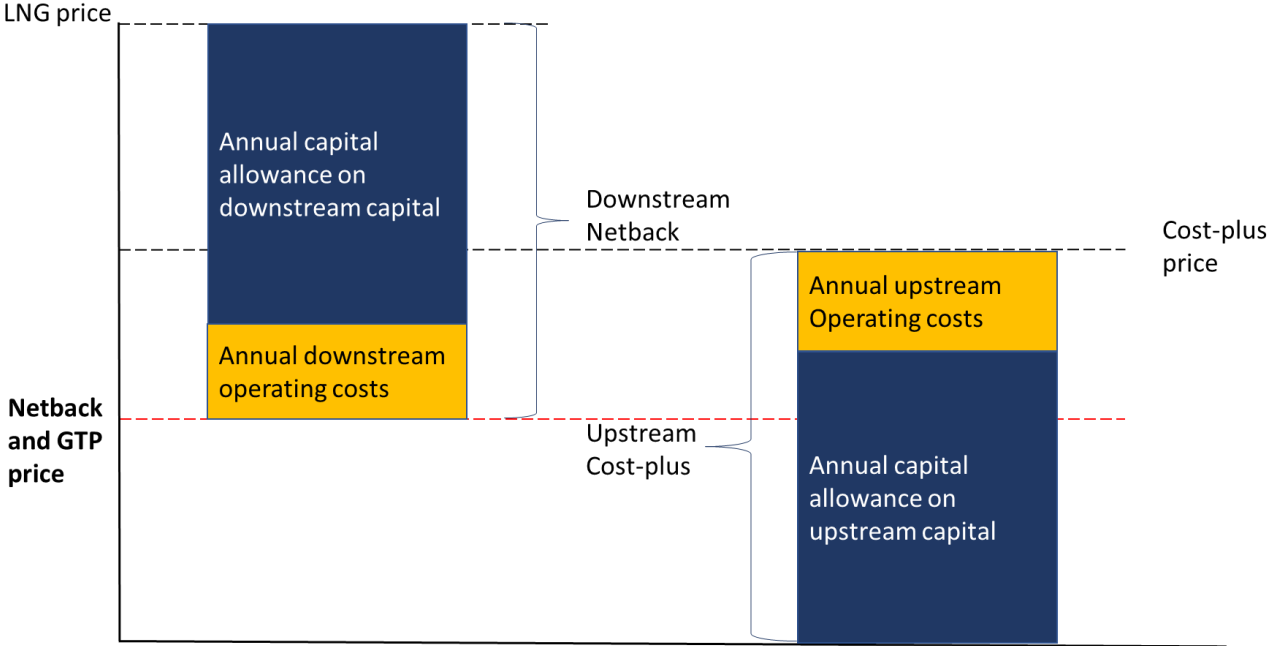
Capital and operating costs are allocated to the upstream and downstream as well as a return on the capital costs. For the upstream, this is a ‘cost-plus’ calculation and is intended to reflect the minimum price the upstream entity would sell feedstock gas from the PRRT project. The underlying resource is not included in the cost-plus calculation. For the downstream, the ‘netback’ calculation is intended to reflect the maximum price they would pay for the feedstock gas.

If there is any residual value (that is, where the netback price is higher than the cost-plus price) the RPM price is set at the mid-point of the two prices. However, when the project is in a notional loss situation (that is, the netback price is lower than the cost-plus price) the loss is attributed solely to the upstream part of the project and the price is derived with reference to the downstream portion only (netback price). This asymmetric treatment of profit and loss situations is further discussed in chapter 6.

A stylised representation of the RPM, where the project is in a profit situation:



A stylised representation of the RPM, where the project is in a notional loss situation:



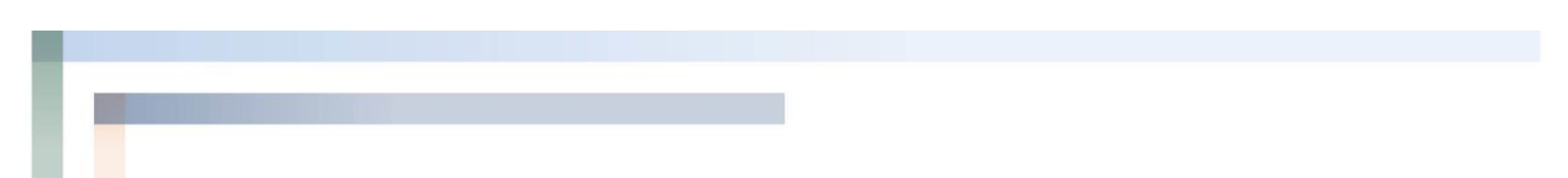
If an APA has not been agreed, and a CUP does not exist, the RPM is used to determine the price of gas at the taxing point. For this reason, the RPM is considered the ‘safe harbour’ pricing method.

In practice, the RPM is almost universally used due to a lack of commercial transactions necessary for a CUP analysis and because the RPM provides generous outcomes to taxpayers, negating the need to enter APAs with the ATO. Feedback from industry and the ATO is that establishing a gas transfer price through the existing APA process can be a significant compliance burden for taxpayers and is resource-intensive for the Commissioner of Taxation.

Underpinning the Arthur Andersen recommendation to adopt the RPM were several assumptions, namely that the:

- LNG integrated project is run as a single project,
- LNG project is already integrated when the price for the gas is being determined,
- Risks associated with exploration activities are not a relevant concern for the upstream operations,
- Upstream and downstream operations carry the same level of risk and expect the same level of returns, and
- Upstream operators would consider that the economic rents inherent in the resource plus the rents attributable to their extraction and processing know-how are equal to rents attributable to the downstream operators’ know-how for liquefaction, marketing, and shipping.

Arthur Andersen acknowledged several caveats to their analysis, including that an arm’s length price determined under legislation should always dominate the RPM approach. Importantly, it acknowledged that the RPM, developed for an emerging industry, may not be suitable once more specific information became available. Also acknowledged was the arbitrariness of some of the RPM design features, such as the central 50:50 profit split feature.



The regulations were adapted in 2013 to factor in the extension of the PRRT to the North West Shelf (NWS) project and extend them to cover integrated gas-to-electricity operations.

The regulations were also remade in 2015 prior to sunset on 1 April 2016. However, the efficacy of the GTP methods was not considered at that time. Rather, changes only modernised the drafting style and incorporated minor amendments to reduce compliance costs for industry, consistent with the then-Government's deregulation agenda.

The current regulations are due to sunset again on 1 April 2026.

3.3 International perspective and treatment

Australia's GTP Regulation is unique in adopting a statutory taxing point for LNG where there is no commercial transaction and, as one submission to the Review noted, no other country in the world uses the bespoke RPM method to determine a gas transfer price.⁹ Australia's main international competitors for LNG have very different fiscal regimes and markets.

The US – soon to overtake Australia and Qatar as the world's largest exporter of LNG – has no need for an RPM-like pricing method, given its structurally different LNG market and the various state-based royalty regimes applying to its oil and gas industry. LNG exporters in the US can draw feedstock natural gas from a vast and geographically dispersed network of domestic gas supply. This market provides observable arm's length reference prices (that is, CUPs) that can be used as inputs for determining royalty liabilities.

Qatar has a very different fiscal regime applying to its oil and gas industry compared to Australia's profit-based PRRT. It has a state-owned corporation with a direct interest in all stages of the gas production value chain, and various production sharing contracts (and other fiscal arrangements) are in place with the Qatari Government for individual gas projects. Such arrangements mean that Qatar can be indifferent as to whether the benefits of gas production are realised by way of dividends from the state-owned corporation or through its taxation arrangements.

The Callaghan Review considered a wider range of resource tax arrangements and found it is difficult to analyse jurisdictions on a comparable basis given the significant variety in approaches taken.

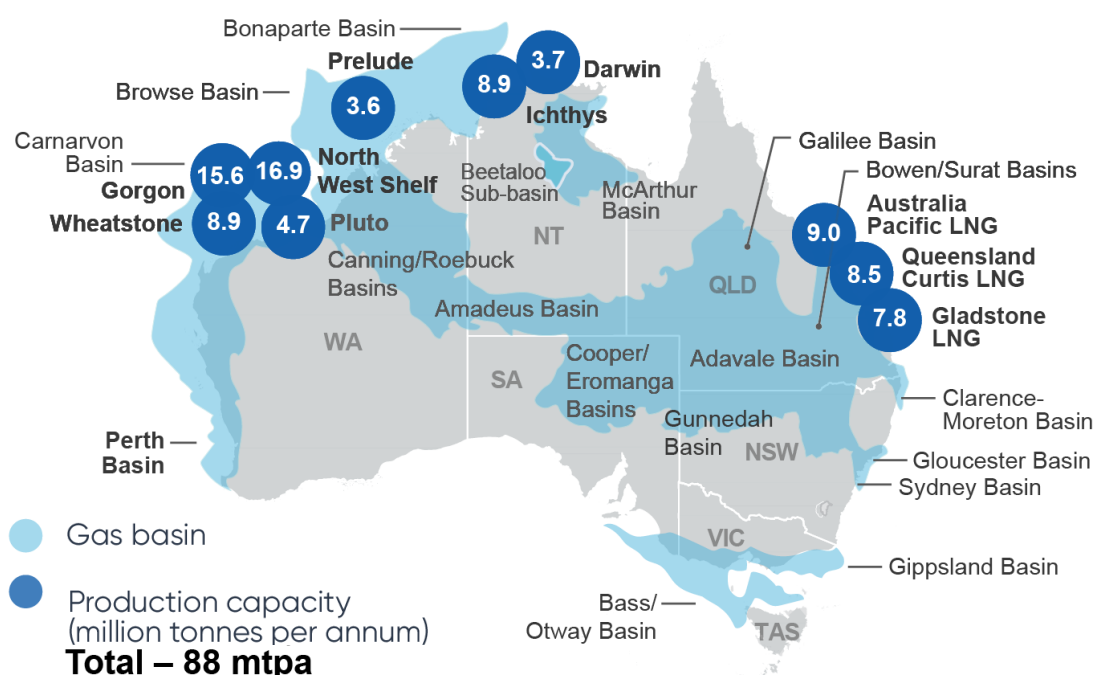
⁹ Dr Diane Kraal, Submission to the GTP Review, p. 7.

4. Industry overview

4.1 Australian LNG exports

Global LNG supply capacity expanded significantly as a result of Australia's \$230 billion LNG investment boom between 2007 and 2012, when final investment decisions were taken on eight major LNG projects. With the last of the projects becoming operational in 2019, Australia now has 10 LNG facilities with a total liquefaction capacity of around 88 million tonnes per annum (mtpa).

Figure 4.1 – Australia's major LNG projects



Source: Resources and energy quarterly, December 2022:

<https://www.industry.gov.au/sites/default/files/2022-12/resources-and-energy-quarterly-december-2022.pdf>

LNG is produced solely for the purposes of transportation to market by ship. Liquefaction cools natural gas to its liquid form, reducing to 1/600th of its volume, thereby enabling it to be shipped. The geographical distance between Australia and key export markets prevents trade through conventional pipelines like those used for domestic gas consumption.

In 2021-22, Australia became the world's largest LNG exporter with a record 83.2 million tonnes exported, comprising 21 per cent of global trade. Industry earnings reached \$70 billion, thus making LNG Australia's second largest commodity export by value behind iron ore (Department of Industry, Science and Resources, 2022)¹⁰. LNG export earnings are forecast to reach over \$90 billion in 2022-23, although the volume of LNG exports is forecast to decline slightly to around 81 million tonnes and stabilise at that level going forward (Department of Industry, Science and Resources, 2022).¹¹

¹⁰ Department of Industry, Science and Resources, *Resources and Energy Quarterly – December 2022*.

¹¹ Department of Industry, Science and Resources, *Resources and Energy Quarterly – December 2022*.

The vast majority of Australia's LNG is exported to the Asia Pacific market, primarily to Japan, China, and South Korea. Almost three quarters of Australian LNG exports are sold under oil-linked long-term contracts, typically of 20 years duration. These contracts link the price of LNG sold to the price of oil (commonly the Japan customs-cleared crude, JCC) with a time lag of around three to six months, depending on the contractual arrangements. The remaining LNG is sold at spot prices or on short-term contracts.

4.2 The major LNG projects in Australia

Australia's LNG industry began with the NWS LNG project exporting to Japan in 1989. The second LNG project – Darwin LNG – was completed in 2006, processing and exporting gas from the Bayu-Undan field in the former Joint Petroleum Development Area (JPDA) shared between Australia and Timor-Leste.

The LNG investment boom that followed was spurred on by a prolonged period of tightness in the global LNG market and a period of high and rising oil prices. Pluto LNG was the first to come online in 2012, followed by the three unconventional coal-seam gas (CSG) projects onshore in Queensland over 2015 and 2016.¹² Gorgon – one of the world's largest LNG projects – shipped its first cargo in March 2016. Wheatstone commenced production in 2017, Ichthys in 2018, and, lastly, Prelude in 2019 – one of the world's first floating LNG facilities. The location and scale of these projects is shown in Figure 4.1.

For a period, the last seven of these major LNG projects were under construction at the same time, representing more than half of the LNG projects under construction globally. This put upwards pressure on labour and material costs and contributed to a substantial increase in total project development costs. Some industry participants have stated that projects tended to suffer cost overruns relative to expectations at the time final investment decisions were taken, which has significantly impacted project economics and their competitiveness. Treasury heard from the industry that most, if not all, projects have turned out to be less profitable than envisaged, confirming the observations made in the Callaghan Review.¹³ By way of example, total project costs for Gorgon were progressively revised from US\$37 billion at FID in 2009 to US\$54 billion in 2013. Consultancy firm Wood Mackenzie's asset report estimates total development costs until the end of 2017 to be US\$60 billion. Other projects, for example Wheatstone and Ichthys, also saw significant cost increases during construction.

The project economics have also been impacted by the resultant LNG supply glut. The LNG investment boom represented not just a major expansion in Australian liquefaction capacity, but also in *global* capacity, thus significantly transforming the global LNG market.¹⁴ The supply glut coincided with a fall in oil prices, accentuating pressures on the projects.

Industry submissions to the Callaghan Review noted that most of the large LNG projects had expectations of high rates of return when investment decisions were taken.¹⁵ However, the cost overruns alongside a difficult price environment as projects transitioned to production resulted in lower rates of return than expected – at least until the surge in oil prices in 2022, arising from Russia's invasion of Ukraine.

¹² Queensland Curtis LNG (QCLNG), Gladstone LNG (GLNG) and Australia Pacific LNG (APLNG).

¹³ See Callaghan Review, p. 23.

¹⁴ Department of Industry, Science and Resources, *Resources and Energy Quarterly – September 2016*.

¹⁵ See Callaghan Review, p. 5.

Lower overall profitability of projects has had implications for returns to the community through PRRT revenue, which will be lower and collected later than expected, particularly given the interaction with carry-forward uplift rates for undeducted capital expenditure, which remains substantial (refer to Chapter 8 for further information).

4.3 Current LNG projects relevant to the GTP Review

Only five of the 10 current major LNG projects are subject to PRRT and thus would be impacted by any changes proposed by this Review. All of these five projects are located off the northwest coast of Australia – Pluto, Gorgon, Wheatstone, Ichthys and Prelude. These projects are subject to the PRRT because the gas fields supporting LNG production are offshore in Commonwealth waters and not subject to other resource tax arrangements.

While the NWS project was brought within scope of the PRRT in 2012, certain transitional arrangements were introduced at the time to ensure recognition of past capital investment as well as the significant federal royalties and excise that the project pays. The way in which those arrangements were designed largely eliminates the possibility that the NWS project will ever pay PRRT, even with changes to the GTP Regulation.

The Bayu-Undan/Darwin LNG project is not a PRRT taxpayer. Instead, LNG produced from gas fields from within the former Joint Petroleum Development Area (JDPA) in the Timor Sea is subject to a Production Sharing Contract (PSC) between the producer and the governments of Australia and Timor-Leste.

The three major LNG producers that source unconventional CSG in Queensland are also not subject to the PRRT following the removal of onshore projects from the PRRT regime in 2019 as part of the Government's response to the Callaghan Review. Instead, these projects deliver a return to the Queensland community for the use of its resources via the State royalty regime.

The key implication of the above is that any change to the PRRT for LNG projects should have no impact on gas supply and gas prices for the East coast gas market, as the five impacted LNG projects off the western and northern coasts of WA do not supply the East coast gas market and the three LNG projects in Queensland are not subject to the PRRT regime.

Treasury also considers that any changes proposed in this Review will not put at risk the supply of natural gas for domestic consumption in the WA and NT gas markets. The NWS, Gorgon, Pluto and Wheatstone supply gas to the WA gas market in accordance with Domestic Market Obligations (DMOs) under WA's domestic gas reservation policy.¹⁶ There are strong commercial reasons for these projects to continue to maximise their overall LNG production, which flows through to their WA supply. In particular, these projects have long-term contracted export commitments and a commercial imperative to make efficient use of their LNG infrastructure and maintain project cashflows. This would also apply to the Ichthys project which supplies some gas to the NT under emergency

¹⁶ Under the WA domestic gas reservation policy, gas equivalent to 15 per cent of LNG produced to supply the global LNG market must be reserved for WA consumers, which complements supply from domestic-only projects using the WA gas pipeline network. The Karratha Gas Plant, part of the NWS project, has been producing domestic gas for WA since 1984. Gorgon started supplying DMO quantities in 2016, Pluto in 2018 and Wheatstone in 2019. Because the Ichthys LNG facility is in the Northern Territory, it does not contribute to WA's overall LNG production capacity and, for that reason, does not contribute to WA's domestic gas supply. Similarly, Prelude is not subject to DMO obligations to the WA domestic gas market as it is a floating LNG facility located offshore in Commonwealth waters.

arrangements when there are disruptions to its gas supply from the Blacktip non-LNG project which is the primary supplier of domestic gas for NT.

However, a key policy consideration is the impact of any changes on the scheduled commencement of the Scarborough project in 2026, which is important for the WA domestic gas market in the medium term. The Australian Energy Market Operator (AEMO) has projected a supply shortfall in a tightly balanced WA market through to 2029.¹⁷ Similarly, Treasury understands that the development of Browse could be an important source of energy supply beyond the medium term for WA, and that Barossa is expected to make an important economic contribution to NT, including to employment outcomes. These proposed projects are further discussed below.

4.4 The next wave of LNG investment in Australia

The Australian LNG industry expects future investment is likely to be in ‘backfill’ projects involving the use (and in some cases, expansion) of infrastructure from existing LNG projects for new gas fields, many of which will operate under a tolling structure, rather than the large-scale integrated developments that characterised the previous LNG investment phase. This type of investment is expected to be more cost competitive as it can make use of existing liquefaction capacity, as current fields become depleted. In a submission to this Review, the Australian Petroleum Production and Exploration Association (APPEA) stated:

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.¹⁸

The first of these arrangements commenced in March 2022, with the announcement that gas from the Pluto fields would be processed through the NWS LNG facility for the period 2022-2025, absorbing the spare capacity arising from the depletion of the NWS gas fields.¹⁹ In addition, announcements have been made for the supply of Waitsia gas to access the spare capacity at the NWS facility from 2025 to 2028. This represents the first time that WA onshore gas will be exported as LNG.²⁰ Beyond 2028, large scale backfill projects are earmarked for NWS LNG to extend the life of the facility. For example, development of the gas fields that lie in the Browse Basin is under active consideration as backfill for the NWS facility, with first gas expected from 2030, pending final investment decisions.

Exploration of the Greater Gorgon area has resulted in numerous discoveries which are expected to be developed as backfill projects to the Gorgon LNG plant beyond 2035. In addition, Wood Mackenzie assumes several Greater Gorgon fields will be developed to backfill the Gorgon LNG facility and extend the life of the project out beyond 2064.

Woodside commenced development of the \$12 billion brownfield expansion of Pluto LNG onshore facilities in August 2022, including construction of a second LNG train, and development of the associated Scarborough gas field, targeting first LNG for 2026.²¹ Some of the Scarborough gas is also

¹⁷ Australian Energy Market Operator, *WA Gas Statement of Opportunities*, December 2022.

¹⁸ APPEA, Submission to the GTP Review, p. 30.

¹⁹ See: <https://www.woodside.com/docs/default-source/asx-announcements/2022/processing-of-pluto-gas-starts-at-north-west-shelf.pdf>

²⁰ See: <https://www.mediastatements.wa.gov.au/Pages/McGowan/2020/12/WA-Government-reaches-agreement-on-job-creating-domestic-gas-project.aspx>

²¹ Australian Energy Market Operator, *WA Gas Statement of Opportunities*, December 2022.

expected to backfill the NWS LNG facility.²² Expansion of the Pluto onshore facility provides the development potential for other third-party gas resources.

Santos announced a final investment decision was taken for the Barossa gas field in March 2021 to backfill the Darwin LNG plant, extending the life of that facility by around 20 years.²³

This follows a drilling program in the Bayu-Undan field which extended the capacity utilisation of Darwin LNG by around a year.

Final investment approval has also been given for development of the Crux gas field as a backfill project for Prelude, with first gas expected in 2026. With the Crux joint venture having a different commercial structure to Prelude, it is expected that a tolling arrangement will be agreed for the use of the Prelude facility.

The nature of this next wave of investment is likely to have different effects on employment than the previous investment cycle. The scale of employment growth that materialised over the period between 2007 and 2014 is unlikely to be repeated. Employment in the oil and gas sector more than doubled from around 12,000 people on average in 2007-08 to around an average of 28,000 by 2014-15,²⁴ but this was largely a result of the greenfield development and construction of eight major LNG projects.

By contrast, employment averaged around 22,000 people²⁵ in 2021-22, the year in which Australia exported a record 83 million tonnes of LNG, demonstrating the production phase of the investment cycle is generally less labour-intensive. It is likely that investment in backfill projects will not see employment rise as much as was seen during the LNG investment boom where labour requirements for construction of liquefaction facilities were significant.

4.5 Broader investment context

Since the release of the Callaghan Review in 2017, global LNG markets have experienced a high level of volatility, which is expected to continue. Oil prices have been below the Callaghan Review's baseline oil price projection of \$US65 per barrel (WTI) for some of the period since 2017, with prices falling during the start of the Covid-19 pandemic. More recently, significant disruptions to global natural gas supply relating to Russia's invasion of Ukraine resulted in a major restructuring of global energy markets and very high prices. LNG netback prices, which averaged \$7.91 per Gigajoule during the period spanning 2016-2020, rose significantly to an average of \$29.08 per Gigajoule during the 2021-2022 period.²⁶

While global prices have fallen, partly in response to rebalancing of European gas inventories and behavioural responses to reduce gas consumption by consumers, global gas prices remain significantly higher than historical averages. The International Energy Agency expects global gas prices to remain significantly higher than historical averages for the next few years, with tightness in the global gas

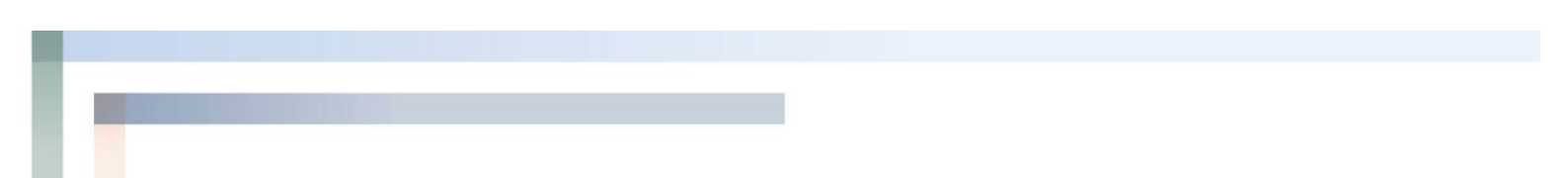
²² Wood Mackenzie Scarborough Asset Report.

²³ Department of Industry, Science and Resources, *Resources and Energy Quarterly – September 2021*.

²⁴ Department of Industry, Science and Resources, *Resources and Energy Quarterly – December 2022 – historical data*, using source: ABS, Labour Force, Australia, cat. no. 6291.0, Canberra.

²⁵ Department of Industry, Science and Resources, *Resources and Energy Quarterly – December 2022 – historical data*, using source: ABS, Labour Force, Australia, cat. no. 6291.0, Canberra.

²⁶ Treasury calculation using source: Australian Competition and Consumer Commission, Gas inquiry 2017-30, *LNG netback price series* <https://www.accc.gov.au>



market not expected to ease until the mid-2020-30s, when new and large LNG projects (particularly in the United States) come online.²⁷

The future of LNG demand after 2030 is uncertain. While Australia's gas resources are expected to have a major role in the world's energy transition, it is not clear how long the transition will be. BP's 2023 Energy Outlook considers a range of scenarios for LNG and notes that:

*'Prospects for natural gas depend on the outcome of two significant but opposing trends; increasing demand in emerging economies as they grow and industrialize, offset by a shift away from natural gas to lower-carbon energy led by the developed world.'*²⁸

Similarly, the 2022 edition of the International Energy Agency's *World Energy Outlook* forecasts that the era of rapid global growth in natural gas demand is drawing to a close.²⁹

Australia's main LNG export markets are to China, Japan and Korea, all of whom have made commitments to change emissions profiles before 2030 and reach net zero emissions by the second half of the century. Future LNG investments will need to deal with a range of regulatory and environmental hurdles to meet the emissions requirements of both Australia and the proposed export market(s). The Government's recently legislated Safeguard Mechanism, which is expected to take effect from 1 July 2023, put Australia on a path to net zero, but means LNG projects will face additional costs for compliance activities associated with emission reductions and offsetting costs.

²⁷ International Energy Agency, *World Energy Outlook 2022* (windows.net) p. 370.

²⁸ <https://www.bp.com/en/global/corporate/energy-economics/energy-outlook/natural-gas.html>

²⁹ International Energy Agency, *World Energy Outlook 2022* (windows.net) p. 25.

5. Stakeholder views

As set out in section 1.3, Treasury has undertaken a substantial consultation process with industry stakeholders since commencing the Review in 2019. The information and views put forward by industry have been highly valuable in developing Treasury's understanding of operational issues associated with the current GTP Regulation and testing possible reforms needed to address issues identified by Treasury.

Set out below is a summary of the key issues raised with Treasury about the GTP Regulation over the course of the Review.

Existing GTP Regulation and potential reforms

Broadly, academics, civil society groups and policy bodies argue that the existing GTP Regulation is not fit-for-purpose and require reform to ensure a fairer return for the community for the use of its gas resources while also enhancing regulatory security and sustainability for the oil and gas sector. Stakeholders drew comparisons between Australia's growth as a major LNG exporter into global markets and declining levels of PRRT revenues payable to conclude the existing GTP settings are no longer appropriate.

The Tax Justice Network – Australia characterised Australia's PRRT regime as '*remarkably generous by global standards*' and submitted:

It is a major national policy failure that while Australia becomes one of the world's largest exporters of LNG, there is no increase in government revenues.³⁰

Professor Richard Eccleston and Mr Lachlan Johnson in their joint submission noted that:

The volume of revenue forgone by the Australian government represents poor value to taxpayers and an unfair return on the exploitation of a commonly-owned resource.³¹

The Australia Institute submitted that, in the interests of ensuring a fair return for the community, the primary goal should be to tax as much of the economic rents from PRRT projects as possible.³²

Unlike submissions to the Callaghan Review³³, submissions to this Review did not call for additional royalties for LNG projects to provide a more reliable and stable flow of revenue, and thus guarantee a return to the Australian community as owners of gas resources. However, some noted royalty arrangements would be more advantageous, pointing to the effectiveness of royalty regimes applying to the NWS project and to the three LNG projects onshore in Queensland.

Given it is outside the terms of reference for this Treasury inquiry to repeal the PRRT and reintroduce royalties, there should at least be more uniformity in Commonwealth taxation of petroleum resources. For example, the [NWS] gas project uses the Netback method for royalty calculation.³⁴

³⁰ Tax Justice Network – Australia, Submission to the GTP Review, p. 1.

³¹ Professor Richard Eccleston and Mr Lachlan Johnson, Submission to the GTP Review, p. 1.

³² The Australia Institute, Submission to the GTP Review, p. 2.

³³ See, for example, the Callaghan Review pp. 9 and 32,

³⁴ Dr Diane Kraal, Submission to the GTP Review, p. 7.

In respect of the specific design of the GTP rules, non-industry submissions generally contended the existing RPM is fundamentally 'flawed' and should be replaced with a netback-only pricing model.

[T]he RPM considers the 'transfer price' to be half way between the netback price and the cost-plus price. This gives away half the rent for free and taxes the remaining half at the internationally-low level of 40%.³⁵

Dr Diane Kraal noted:

The RPM is a key causal factor to the problem of low PRRT revenues, and a change in method is required for remediation...

...The Australian government (on behalf of the community-owners) allows a zero valuation of gas reserves at the wellhead under the Cost-Plus method...

...The RPM clearly disadvantages the wider Australian community as the owners of gas resources. The flaws in the RPM have resulted in the Australian government missing out on millions of dollars in tax since the [GTP] Regulations were first introduced in 2005.³⁶

Tax Justice Network – Australia noted that the current RPM creates ample opportunity for transfer mispricing by companies in integrated gas projects.³⁷

Some noted that the 50:50 residual profit split is not based in economics, logic or principle and the netback represents a fairer and simpler approach.

There is no reason to believe the RPM's 50:50 profit split genuinely reflects an economically valid allocation of risks between upstream and downstream business units.³⁸

Non-industry stakeholders also considered that a netback-only pricing methodology would facilitate greater transparency and thereby enhance integrity of the PRRT. This would provide assurance to the Australian community that they are getting a fair return, noting the PRRT's vulnerability to profit shifting and transfer mispricing.

Much needed reform of the current transfer pricing rules has the potential to generate a significant increase in PRRT revenue and boost public confidence in the probity and effectiveness of the system without compromising the [oil and gas] sector's competitiveness or investor confidence.³⁹

One non-industry submission advocated to shift the taxing point, so it aligned with an arm's length sale of LNG, noting the interdependent and integrated nature of the product.⁴⁰

The point was made that pressure on the Government to change the GTP Regulation will remain for as long as the Australian community lacks confidence that it is receiving a fair return from the use of its gas resources. In this regard, it is argued that GTP reforms that ensure a fairer and more transparent mechanism for allocating profits between the upstream and downstream activities will enhance fiscal stability for the oil and gas sector into the future.⁴¹

³⁵ The Australia Institute, Submission to the GTP Review, p. 2.

³⁶ Dr Diane Kraal, Submission to the GTP Review, p. 2, 6 and 7.

³⁷ Tax Justice Network – Australia, Submission to the GTP Review, p. 8.

³⁸ Tax Justice Network – Australia, Submission to the GTP Review, p. 7.

³⁹ Professor Richard Eccleston and Mr Lachlan Johnson, Submission to the GTP Review, p. 1.

⁴⁰ Mr Wayne Mayo, Submission (2019), p. 4-5.

⁴¹ Tax Justice Network – Australia, Submission to the GTP Review, p. 1.

One non-industry submission was not supportive of changes to the RPM.⁴²

By contrast, the collective view of the industry – largely maintained throughout all PRRT consultative processes, beginning with the Callaghan Review – is that the GTP Regulation is working as intended and remains best practice for the industry. Submissions from industry representatives, such as APPEA, called attention to the 1998 Report by former accounting firm Arthur Andersen and the co-design process between government and the industry that followed.

Industry contends that the conclusions and analysis outlined in the 1998 Report still form a sound basis for the GTP Regulation 20 years on, particularly the RPM and residual profit-splitting methodology. APPEA submitted:

*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.*⁴³

*A key threshold question related to the allocation of rent between the upstream and downstream segments of an integrated project [...] 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.*⁴⁴

Industry participants acknowledged the arbitrary nature of the 50:50 profit-split and its asymmetric application to a notional loss, but proposed that it nonetheless constituted a ‘a workable solution to calculating proxy transfer prices in line with the PRRT legislation’⁴⁵ and should be retained on that basis. PwC submitted that the general complexity associated with applying transfer pricing principles means that the existing RPM is the method that ‘provides the greatest transparency and simplicity for what is a complicated issue’.⁴⁶

Both MIMI⁴⁷ and Shell⁴⁸ submitted that the GTP Regulation is working as intended and remains appropriate for existing and future projects. Woodside submitted that the existing GTP Regulation has provided certainty for industry and have underpinned the record levels of investment in Australian LNG projects.⁴⁹

Industry supported the proposition put forward in the 1998 Arthur Andersen Report that the gas itself is worth little without a mechanism to get it to market (through liquefaction), and the processing infrastructure is worth little without access to a large and sustainable supply of cost-effective gas.⁵⁰

⁴² Mr Chris Hood – Submission to the GTP Review.

⁴³ APPEA, Submission to the GTP Review, p. 7.

⁴⁴ APPEA, Submission to the GTP Review, p. 20.

⁴⁵ APPEA, Submission to the GTP Review, p. 23.

⁴⁶ PwC, Submission to the GTP Review, p. 10.

⁴⁷ MIMI, Submission to the GTP Review, p. 2.

⁴⁸ Shell, Submission to the GTP Review, p. 2.

⁴⁹ Woodside, Submission to the GTP Review, p. 3.

⁵⁰ Arthur Andersen Report, p. 23-5, as referenced in the APPEA Submission to the GTP Review, p. 20.

For instance, MIMI submitted:

The risk sharing and interrelationship of the upstream and downstream portion of integrated projects is a key characteristic of LNG production. The gas has limited commercial value without access to a market, and the significant operational excellence and intellectual property brought to the downstream portion of LNG production creates the opportunity to market that gas (via liquefaction). Conversely, the processing operations are worth little without a significant and reliable source of feedstock gas.⁵¹

Industry's view is therefore that value is created at all steps in an integrated project, and that any attempt to allocate any value-creation and risk drivers to different parts of the supply chain would be 'conceptually flawed'.⁵² Industry argues that there is no evidence available to underpin any rationale for change.

The unanimous view of industry was that the adoption of a netback only approach in the GTP Regulation would have detrimental impacts on future investment, including with respect to increases in supply costs and attraction of project capital. Industry participants who considered modifying the RPM by revising the 50:50 profit split to 80:20 preferred this option over the netback only approach, noting concerns that a netback only approach would not appropriately reward contributions from the downstream. It was noted, however, that modifying the RPM to 80:20 could still curtail investment given the sensitivity of new projects to PRRT changes, as discussed further below.

Submissions also noted the relationship between commodity prices and PRRT payable. For instance, MIMI submitted that current low PRRT receipts are not attributable to an inappropriate gas transfer pricing mechanism but are instead 'due to both the relatively low commodity prices in recent years, and the early stage of the lifecycle of many of Australia's LNG projects'.⁵³

Industry also noted that the PRRT was a secondary tax and considered a significant tax contribution would be provided from projects through corporate tax. They considered that the combined effects of corporate tax and PRRT, as well as other factors, meant Australia was a high-cost country in which to invest and if projects did not go ahead, not only would Australia lose revenue from PRRT but corporate tax as well. Industry also highlighted the further risks to future domestic supply, particularly for WA, should new projects not proceed.

Industry argued that replacing the RPM with a netback method would represent a fundamental shift in scope of the PRRT as it would have the effect of levying PRRT on the value-adding contributions of the downstream activities – tantamount to imposing a new tax on downstream activities. Moving to a netback dismisses the contribution of the downstream activities whereas value is created at every stage of the LNG process and economic rent cannot be assigned to any particular stage. It was also noted that moving away from a predictable self-assessment mechanism would result in additional compliance and substantiation issues.

Industry views on the components of the RPM that raise issues are set out further as part of the analysis in section 6.2 below.

⁵¹ MIMI, Submission to the GTP Review, p. 3.

⁵² APPEA, Submission to the GTP Review, p. 22.

⁵³ MIMI, Submission to the GTP Review, p. 3.

Effect of change on LNG Investment

The unanimous view of industry was that any changes to the GTP Regulation would have significant impacts on future investment in Australian LNG projects, with some projects potentially being discouraged from proceeding.

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.⁵⁴

A stable and neutral taxation regime is essential to encourage development of resources by allowing a return on investment commensurate with the risk of exploration and development. Adverse fiscal regime changes may discourage already challenging projects to remain undeveloped. MIMI is particularly keen to ensure that changes to the PRRT regime do not risk the economic viability of the Browse project.⁵⁵

Comments on the impact on investment were provided in the context of an increasing trend towards tolling and backfill projects (which use existing liquefaction infrastructure) rather than new greenfield projects. It was highlighted that the economics of such projects are likely to be more sensitive to PRRT changes (including to the GTP methodology) given their lower capital expenditure profiles, and thus lower deductions to offset assessable PRRT receipts. Industry argued that these projects are likely to pay earlier and materially higher PRRT amounts than the foundational major LNG projects. But given tax, including PRRT, makes up a larger proportion of costs for these projects, they would be put at risk if GTP changes were made.

Independent industry analysts supported the view that, to the extent changes to the PRRT brought forward and/or increased expected PRRT payments, Australia would inevitably become a relatively less attractive country for future investment compared to other destinations. They noted PRRT changes would be coming on top of other significant policy changes and while each policy change might be justified on its own, when taken cumulatively, they could be expected to have an impact on the investment climate. They considered, however, that already sanctioned projects would still be likely to proceed.

Independent industry analysts also noted that the tax and regulatory environment are just some of the factors that contribute to whether a project goes ahead, and other factors were also important if not more so. The most important of these include the price of and demand for the project's gas and expected project costs. It was also noted that any additional impact on the investment climate for the LNG industry needs to be balanced against the fact that the PRRT is not seen as delivering for the Australian community.

Fitness of existing rules for future industry arrangements (including tolling)

Community groups and academics were generally of the view that the existing PRRT settings, including the GTP Regulation, are no longer fit-for-purpose.

⁵⁴ APPEA, Submission to the GTP Review, p. 82 (referencing a 2019 Wood Mackenzie paper).

⁵⁵ MIMI Submission to the GTP Review, p. 3.

The Tax Justice Network – Australia submitted that ‘a fair and fundamental change to the gas transfer pricing arrangements for current and future projects would enhance regulatory security and stability for the oil and gas sector.’⁵⁶

The overarching industry view was that the existing rules are well-suited for future arrangements, and that current the GTP Regulation accommodates tolling and third-party processing arrangements.

*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 [...] The RPM in its current form largely works well where there is expanded use of existing infrastructure and support its continued application.*⁵⁷

Woodside submitted:

*[T]hat the existing regulations provide appropriate technical and practical outcomes for projects involving tolling arrangements.*⁵⁸

Some industry submissions also raised the view that the existing GTP Regulation, while generally appropriate for tolling arrangements, would benefit from further clarification. In the broader context of tolling and shared infrastructure arrangements, submissions also raised concerns around the potential need for commercially sensitive information to be shared amongst unrelated parties (including where they are third-party competitors) on the basis this would likely be commercially and practically difficult.

The use of CUPs

Broadly, all stakeholders identified that there are no feasible CUPs in the market for LNG feedstock gas which could be readily employed in the context of the GTP methodology. Furthermore, several stakeholders, including APPEA,⁵⁹ MIMI,⁶⁰ Woodside,⁶¹ PwC⁶² and KPMG⁶³ each made representations to the effect that comparable uncontrolled prices (which would allow for meaningful comparison) are highly unlikely to exist in future.

Using a CUP would require unique modifications departing from OECD principles, inserting additional complexity and uncertainty, and consequently, increasing compliance costs. Some submissions noted that it is arguably impossible to obtain all the information on the CUP to make the necessary and sufficiently reliable comparability adjustments for each particular LNG project.⁶⁴

Start date of changes

Industry was of the view that if any changes are adopted, they should apply to new production licences issued after the start date of enabling legislation. In addition, some submissions argued that

⁵⁶ Tax Justice Network – Australia, Submission to the GTP Review, p. 1.

⁵⁷ APPEA, Submission to the GTP Review, p. 30-1.

⁵⁸ Woodside, Submission to the GTP Review, p. 7.

⁵⁹ APPEA, Submission to the GTP Review, p. 9.

⁶⁰ MIMI, Submission to the GTP Review, p. 3.

⁶¹ Woodside, Submission to the GTP Review, p. 10.

⁶² PwC, Submission to the GTP Review, p. 6.

⁶³ KPMG, Submission to the GTP Review, p. 3.

⁶⁴ See, for example, KPMG, Submission to the GTP Review, p. 3.

projects that have already received final investment approval should not be impacted if subsequently combined with production licences issued after the effective date for GTP changes.⁶⁵

By contrast, non-industry groups consider that changes should be applied to all existing projects as well as future investments to ensure a fair return to the Australian community for the exploitation of its gas resources, and to maintain a consistent and transparent approach across all LNG projects covered by the PRRT.

⁶⁵ See, for example, Chevron Submission to the GTP Review, p. 2-4.

6. Analysis and options

Treasury has examined the GTP Regulation with reference to the appropriateness of the initial analysis of the Arthur Andersen process, the pattern of LNG development observed in Australia to date and likely LNG developments into the future, and feedback through consultations.

Treasury considers that the assumptions and analysis underpinning the current design of the RPM are no longer appropriate and do not align with modern transfer pricing principles, with the consequence that the current configuration of the RPM does not deliver an arm's length price for gas used in LNG production. For that reason, to the extent that there are profits attributable to resource rents in LNG production, they are escaping the PRRT net.

To address this structural undervaluation of gas, Treasury recommends replacing the RPM with either a netback only method or a modified RPM. Treasury acknowledges that such a change would impact existing projects that were sanctioned and constructed based on current settings. Such a change could also impact the economics of future projects that are likely to have lower overall construction costs as they leverage existing infrastructure. As an alternative, a cap on the use of deductions to offset assessable PRRT income earned by LNG producers could be introduced to address issues around the timeliness of PRRT payments and ensure a minimum return to the community from the offshore LNG industry.

These approaches will ensure the PRRT is fit-for-purpose in respect of LNG production into the future.

Recommendation 1

Modify the existing 'safe harbour' transfer pricing method – the 'Residual Pricing Method' (RPM) – to ensure gas is more fairly priced at the PRRT taxing point for integrated LNG projects. Treasury recommends either a netback-only approach or modified RPM (80:20 profit split) be adopted.

Alternatively, limit deductible expenditure to the value of 90 per cent of PRRT assessable receipts in respect of each project in the relevant income year (applied after mandatory transfers of exploration expenditure). Unused denied deductions would be carried forward and uplifted at the Government long-term bond rate.

6.1 The evidence suggests the RPM under-prices gas

The cost-plus component of the RPM excludes the value of the resource

Economic rents refer to returns that are greater than economically necessary to keep assets and/or labour deployed in their current activity. That is, returns beyond those received from normal commercial value adding in a competitive market.

For non-renewable resources, economic rents occur because not all deposits are the same and usually the best/lowest cost ones are developed first. Lower cost resources are typically advantaged in some way, for example they may have lower extraction costs, fewer impurities, lower carbon storage requirements/costs, lower costs per unit because of size or proximity to existing infrastructure. Investors aim to develop inframarginal projects or those deposits with the highest expected profits first. Hence most resource developments are undertaken with the expectation of rents or above normal returns.

General market dynamics and commodity cycles also play a role in industry profitability and creation of economic rents. When commodity prices are higher, they deliver greater profitability than might be required to receive a 'normal' commercial rate of return on an investment, that is, create economic rents, especially for lower cost projects.

The logic underpinning the RPM is to allocate a notional commercial return, which includes a degree of normal profit (adjusted for reasonable risk), to all identifiable functions in the project with the exception of the resource in order to identify if there is any residual profit (economic rent) remaining.

To the extent there is residual profit, this could be attributable to the resource, which is treated as a zero-cost input into the RPM calculation, or it could be attributable to other parts of the production chain to the extent they add value beyond normal commercial value adding (which has already been accounted for in the initial allocation of profits). The question Treasury has had to grapple with, and has questioned industry and other interested stakeholders on, is what are the clearly identifiable factors in the production chain other than the resource that could account for residual profits.

As noted in chapter three, the value of the upstream activities is determined using the 'cost-plus' method, which includes the upstream operating costs associated with producing natural gas as well as an appropriate amount reflecting a notional and fixed gross profit on those costs (that is, the 'normal' return required by a gas producer to sustain the operations), represented by the Government long-term bond rate (LTBR) plus 7 percentage points. Using a standard, notional and fixed gross profit margin only applying to upstream infrastructure and running costs means that no account is made for the gas resource used as an input to that production; instead, that value is incorporated into the residual profit determined at the end of the RPM calculation and subject to the 50:50 profit split. Thus, the RPM assumes that the value of the underlying resource can at most account for 50 per cent of the residual profit or rent.

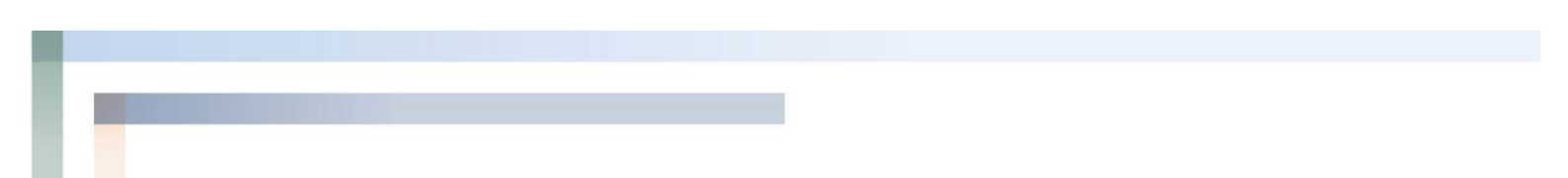
In a project where the return on upstream plus return on downstream equals the observed LNG price, then at that point in time, there is no residual profit/economic rent in the project. If supply and demand conditions change such that the price of LNG increases above the neutral price, economic rent is generated in the project without anything different or special having been done in the upstream or downstream activity. This underpins the central argument that the primary source of economic rents vest in the resource. It is above this neutral point where the economic rents are created that the community should share in this value. At present, the RPM limits this to no more than half the value being shared with the community.

The RPM attributes 50 per cent of economic rents to the downstream activities in all cases

Economic rents other than those attributable to the value of a resource might commonly occur due to such factors as:

- regulatory restrictions, for example certain qualifications being required to perform particular activities,
- significant product differentiation of manufactured goods attracting a brand premium,
- geographic factors such as a conveniently located business that can charge higher prices, and
- the use of closely held technology that lowers production costs more than competitors. This cannot apply to an industry as a whole, only those whose cost of production is lower than average.

For PRRT purposes, the downstream component of LNG production comprises all the functions from the point at which sales gas is produced and up until the point where LNG is sold. This endpoint is



typically the adjacent 'free-on-board' (FOB) shipping point. The main functions of this downstream are liquefaction, storage prior to shipping and loading onto the ship

It is not in dispute that each function in the downstream adds value, but value-adding is not the same as generating economic rent.

Treasury considers that the 50:50 profit split attributes too much rent to the downstream for the following reasons:

- LNG is highly commoditised, and so there is likely to be little brand premium associated with every company's LNG. While some LNG producers provide LNG to the particular specifications of customers, and thus may attract a brand premium as a result, that brand premium may be attributable to reliability of supply or to particular qualities of the resource and subsequent processing.
- Marketing activities of LNG companies are highly varied and operate on a range of different models. Some LNG producers utilise marketing or trading hubs that purchase LNG from Australian operations to on sell to third parties. These hubs are often located in foreign jurisdictions and the profits attributed to this part of the value chain are generally not captured in Australia's income tax or PRRT bases.⁶⁶ Attribution of further residual profits to these activities is therefore unnecessary.
- While shipping is outside of the notional downstream entity, the costs of shipping are an important component calculating PRRT revenue when the price received for LNG includes shipping. There may be monopoly rents attributable to shipping at particular times in the LNG investment cycle, however it is unlikely that there are consistent rents over the longer term.
- All projects cannot have lower production costs than every other project through the use of closely held liquefaction technology. Lower costs of production cannot apply to an industry as a whole, only to those whose cost of production is lower than average.
- LNG plants are unique, valuable and highly specialised pieces of infrastructure incorporating complex engineering and intellectual property. They may be a potential source of economic rents, but not to the extent of 50 per cent. LNG plants are designed to process particular gas reserves and to liquefy that gas to the specifications of the particular market or global market to which they sell. The value of the LNG plant will be reflected in the return provided to compensate for the costs of construction (including if the construction of complex parts of the plant were outsourced to a third party or reflected intellectual property), wages and materials. The notional upstream component of the LNG plant comprises those processes to remove impurities from the gas for liquefaction, while the notional downstream component of the plant comprises those parts of the plant used for liquefying the gas.
- Some downstream operations may rely on licenced liquefaction technology or other intangibles for which payments are made and included as part of the netback. Any rents attributable to these unique and valuable intangibles will be effectively captured in the netback as a downstream cost. Likewise, any payments made by a taxpayer to related parties under a cost sharing arrangement or

⁶⁶ The ATO addresses aggressive tax planning involving transfer mispricing of commodity exports to related party hubs. Where appropriate, it has adjusted prior year income tax returns and agreed acceptable pricing for future years.

unrelated parties that transfer profits out of the project would similarly be recognised by the netback. A profit split that assigns residual profits to the downstream may be assigning value to intangibles or other functions that have already been accounted for through the netback, artificially reducing the value of the upstream operation.

The nature of future LNG development in Australia is also evidence that there is likely to be less economic rent in the downstream. The ability to exploit new deposits at lower cost and to prevent LNG processing assets from being stranded is reflected in recent investment decisions in new projects. New investments have highlighted the preference of gas owners is to retain ownership of the gas while potentially outsourcing downstream activities, including liquefaction, shipping, and marketing on a fee-for-service basis (tolling). That 50 per cent of any residual profit will be allocated to the downstream (and consequently excluded from the PRRT net) under the current RPM configuration despite the taxpayer outsourcing those functions is clear evidence that the current RPM is not an appropriate approach for all projects.

6.2 Analysis of the RPM assumptions

The RPM is based on the OECD's 'residual profit split' method

The RPM is not an internationally recognised transfer pricing method. Rather it is modelled on a 'residual profit split' analysis in the OECD Transfer Pricing Guidelines. Transfer pricing methodology has progressed significantly since the RPM was conceived. The OECD published revised guidance on residual profit splits in June 2018.

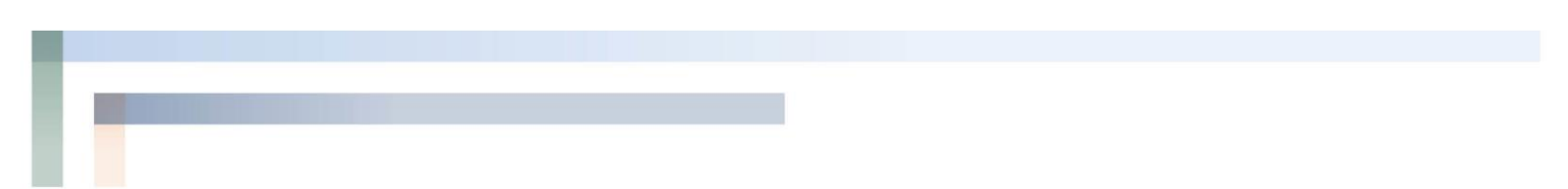
A profit split is generally used as a solution:

- Where both parties to a transaction make unique and valuable contributions (that is, contribute unique and valuable intangibles) to the transaction. Contributions are considered unique and valuable where they are not comparable to contributions made by uncontrolled parties in comparable circumstances, and they represent a key source of actual or potential economic business operations.
- For highly integrated operations where a one-sided method would not be appropriate. A high degree of integration means that the way in which one party to a transaction performs functions, uses assets and assumes risks is interlinked and cannot reliably be evaluated in isolation from the performance of another party. Another example may be a high degree of interdependency.

As described by the OECD, a residual analysis divides the relevant profits from the controlled transaction under examination into two categories.

In the first category is profit attributable to contributions which can be reliably benchmarked, typically being less complex contributions for which reliable comparables can be found. In the second category is the allocation of any residual profit (or loss) remaining after allowing for the profits attributable to the first category of contributions. Typically, this would be based on an analysis of the relative value of the second category of contributions, supplemented where possible by external market data that indicates how independent enterprises would have divided profits in similar circumstances.

The first category would generally not account for the return generated by the second category of contributions which may be unique and valuable, and/or are attributable to a high level of integration, or the shared assumption of economically significant risks.



The residual profit approach was considered by Arthur Andersen to be appropriate because projects were designed and planned as “highly integrated” projects and because value would be added at all stages of the value chain. Treasury considers that while projects may be integrated in the engineering sense, it does not follow that they are or need to be highly integrated from an economic analysis and commercial perspective. The emergence of tolling demonstrates that project functions which are integrated in an engineering sense can be commercially contracted out.

Moreover, in designing the RPM as the default method for use across the industry, the relevant analysis was not done on an individual project basis – as the OECD guidelines prescribe in respect of a residual profit method – but rather industry as a whole. Therefore, the assumptions that the profit split is based on need to hold true not just for one project but for all projects. While value may be added at every stage in an integrated operation, the identification of residual profits attributable to *unique and valuable* contributions from parts of the operation is a different inquiry. As outlined above, there does not appear to be strong justification for the use of a transactional profit split beyond the integration of the projects.

The assumptions that informed the original design of the RPM have not proven to be correct

The original RPM was designed before any of the LNG projects that used them had been sanctioned or built. The design of the RPM and the underlying assumptions warrant re-consideration given the time that has passed since their original design and the number of projects that now use the GTP Regulation.

The first issue is that the analysis sets the RPM up as a hypothetical negotiation after both the upstream and downstream have been built, which then makes no distinction between the potential for the downstream business in this scenario to capture economic rents (by virtue of being a monopoly buyer) and *creating* economic rent. This starting point is not consistent with a profit-maximising commercial strategy by the upstream owner in terms of resource development. An upstream owner, with a potentially valuable resource, would not develop a gas field to allow an independent downstream buyer to capture the economic rent. A realistic assumption is that the upstream owner would pursue a vertically integrated model to retain the rents – exactly the development concept we have seen the industry pursue to date.

Second, the Arthur Andersen analysis states that the gas is not worth anything without a means to get it to market, while the downstream is not worth anything without a resource to process, and so concludes that the residual rents might as well be equally shared. This assumes that dependency means value should be shared equally, an assumption that does not always hold true. For example, highly profitable enterprises may depend on services such as transportation to get products to market. It does not follow that transportation providers would automatically share in such profits beyond receiving a standard commercial return.

The liquefaction process does have the benefit of transforming the underlying gas resource into a product that can be exported and, therefore, access to global markets (demand) and prices that may be higher than if supplied domestically (since oversupply domestically would force prices lower to a point that it would not be economic to develop new supply). This is not necessarily the same as creation of substantial economic rents, in the same way that shipping – which also opens access to export markets – does not. It is noted that liquefaction does involve different risks to shipping. For example, the liquefaction facility is generally immovable (with some exceptions) and is closely tied to the location of the resource and could be left stranded and not redeployed when the resource is depleted. In contrast, a shipping fleet can be redeployed elsewhere. However, this different risk profile should primarily be reflected in the risk-adjusted rate of return on the assets that provide the

services and does not itself provide a justification for a significant share in the economic rents, particularly to the extent of 50 per cent for all projects.

The comparison to shipping is not to demonstrate that there are *no* rents in the downstream. Rather it illustrates the inaccuracy of the assumption that because there is integration and dependence in all projects, there must also be an equal share of rent in the downstream in all projects. As the assumption does not hold in all cases, it is inappropriate to conclude without further analysis that dependency is justification for assuming an equal split of residual profit. It is not obvious that the downstream LNG conversion 'know-how' and marketing expertise is of equal value to the value of the gas as well as the upstream expertise and know-how for finding and developing the gas reserve, extracting the gas and processing it so that it is ready for liquefaction.

Third, it assumes upstream and downstream developers face the same risks and expect the same level of returns. In practice, the risks of operating an LNG plant, transportation and marketing would appear different to those associated with upstream petroleum development and extraction.

Treasury understands that projects were designed and financed as a single project and, as a result, the entities involved do not differentiate the return required from different parts of the LNG production process. However, it does not follow that the tax settings which target only part of the production chain should also make this same assumption. The way a project is structured and conceived by its owner should not drive the sales gas pricing analysis or the tax settings that determine the value at the taxing point. The current settings reflect an approach to pricing where the project design choice of industry participants has dictated the design of the RPM and, ultimately, the amount of PRRT payable. The credible approach is to design a pricing method based on an economic analysis of what would happen between two notional entities. In conclusion, Treasury does not consider that there are no rents in the downstream, rather that the primary source of rents, to the extent they exist, derive from the underlying resource and that rents should not be assumed to be consistent or large in the downstream for all projects.

The RPM attributes a notional project loss to the upstream part of the business only

Another outcome of the RPM is that the upstream part of the business bears all the project losses in the event of low LNG prices but receives only half of the upside profits when LNG prices are high. This occurs because the netback price is deemed as the gas transfer price when it is lower than the cost-plus price.

This asymmetric treatment of notional losses in the RPM is inconsistent with the guidance provided by the OECD on the application of the transactional profit split.

‘The determination of the relevant profits to be split and of the profit splitting factors should generally be used consistently over the lifetime of the arrangement, including during loss years, unless the rationale for using differing relevant profits or profit splitting factors over time is supported by the facts and circumstances and is documented. (OECD transfer Pricing Guidelines 2.148, p 137’)

Treasury could not identify a rationale for the asymmetric treatment of notional losses in the RPM and does not consider there to be a compelling reason in principle to deviate from the OECD’s guidance.

Other features in the RPM design

Exploration and early development costs are excluded from the upstream cost base

The RPM currently excludes some early development costs, including exploration costs and the costs of feasibility or environmental studies prior to production of sales gas. This is inconsistent with the OECD Transfer Pricing Guidelines and with the application of the cost-plus and transactional profit split methods in practice.

The OECD guidelines suggest that:

- an incremental cost-plus should only be used in cases where ‘transactions represent a disposal of marginal production’ (OECD Transfer Pricing Guidelines, 2.57 page 110). Given that the cost-plus method is being applied to the major output of these projects it is difficult to see how the exclusion of some costs is appropriate. Further, a cost-plus method that only rewards marginal expenses is generally not appropriate for a business that is undertaking entrepreneurial activities and assuming higher risk such as upstream petroleum operations.
- The guidance on the transactional profit split method also factors development costs into both the contribution (OECD Transfer Pricing Guidelines, 2.151, page 138.) and cost-based profit splitting factors analysis (OECD Transfer Pricing Guidelines, 2.181 – 2.182 page 146.). The guidelines note that as part of cost-based profit splitting factors, development costs may have been incurred several years in the past and it may be necessary to bring historic costs to current values.

The cost-plus method currently undervalues the contribution of the upstream business because it excludes exploration and other early development costs. The current cost-plus method is an incremental cost-plus method as it only considers the necessary costs to produce gas and to move it to the liquefaction plant. As a result, it has an inbuilt assumption that the notional sale of gas at the taxing point represents ‘a disposal of marginal production’. As a result, the cost-plus method, in its current form, is an inappropriate method for valuing the contribution of an upstream commodity business which is selling the commodity based on which the project was designed and funded. If the cost-plus is maintained as an input into the profit split, then it should be modified to ensure it better reflects the whole contribution of the notional upstream business, including early development costs.

The RPM inappropriately depreciates upstream assets

In some cases, the upstream assets are depreciated each year. This occurs when there is oil or condensate (that is, other MPCs) extracted prior to the production of project sales gas, and occurs in addition to a pro-rata reduction of relevant capital costs to account for their use in producing those other MPCs. By contrast, capital costs for assets used solely for project sales gas and LNG continue to be uplifted over the same pre-production period as they are not used.

The practical effect of this is that the upstream capital costs are reduced over the period in which the other MPCs are produced while the capital costs for the downstream infrastructure are uplifted (sometimes to an inappropriate extent, as noted below).

This design feature would appear to reflect the incremental cost assumption underpinning the cost-plus method, but this would only be valid if the upstream assets were built for the purpose of extracting the other MPCs and the LNG production reflected a late decision to monetise gas. This was not the intention for the RPM’s application to Australia’s major projects, which were built to produce LNG from the outset.

RPM augmentation rules inappropriately inflate capital costs

The rules provide for the augmentation of capital costs in situations where:

- A unit of property is constructed over a period of time and completed after the production year. It became apparent during this Review that it is possible to arrive at two interpretations of how the included capital cost is calculated. The first way is that the final total cost of the unit is augmented for the number of calendar years between the start of construction and the final cost year. The second way is that the costs that are incurred in each year between the start of construction and the final cost is augmented, and the total is included as the final cost. Industry has submitted that in practice the second approach has been applied.
- Where a depreciating asset is completed and all its costs have been incurred, but its use in an integrated LNG operation has not commenced, capital costs are augmented to provide a return to capital for costs incurred prior to the commencement of the operational use.

These rules appear designed to provide a return on capital for the period prior to first use of the asset and for the period once the capital is committed but not yet used. They result in the value of the assets being inflated, in some circumstances significantly, prior to the calculation of the relevant capital return.

While these rules apply equally to both upstream and downstream assets, the practical effect where other MPCs are produced first is that the capital costs for much of the upstream infrastructure will be reduced (because of the depreciation anomaly described above) while the capital costs for the downstream infrastructure will continue to be uplifted.

Conceptually, augmentation should apply to costs incurred each year rather than to the total cost of the asset. It is recommended that the augmentation rules be revised to ensure that the costs incurred during the start of construction of a unit property until the final cost year is augmented each year (the year the cost is incurred) and the total of these amounts be included as the final cost for that unit of property.

A return on capital prior to a capital outlay or the use of assets to generate income is commercially unrealistic. By contrast, preservation of the value of the asset over multiple years (for example, at the GDP deflator) would better reflect a commercial arrangement between upstream and downstream, where each party is responsible for an efficient allocation of capital prior to the project commencing.

Consideration of the main arguments against change

Industry submissions have not identified a consistent source of economic rents across the industry in the downstream components of the business that match the economic rents in the underlying resource and justify an equal share of the overall rents in a project. Instead, the submissions have largely relied on three points to argue why the current arrangements are appropriate:

- The projects were planned as integrated projects and therefore all risks and rewards should be shared equally across the entire project.
- Value is added at each and every stage of the project.
- There is no compelling actual or theoretical basis to determine how residual profits should be split or that change should be made.

Industry also argues that as these rules were subject to an extensive design process when they were developed and that nothing of significance has changed since then that warrants changes to the rules.

Treasury is of the view that these arguments fall short of supporting the continued application of the current model.

Treasury agrees that the projects were planned from an engineering and commercial perspective as integrated projects but does not agree that this should drive the allocation of value for tax purposes. The allocation of value for tax purposes should follow economic principles of what produces value within the project.

Treasury agrees that value is added at every stage of the project but that is not necessarily equivalent to creating economic rent. Where no rent exists, the value should be reflected in the ordinary risk adjusted return attributed to downstream functions rather than receiving a share of economic rents on top of the commercial rate of return.

Treasury considers that no compelling case or theoretical basis exists for consistently allocating 50 per cent of the residual profits to the downstream. If there was a consistent source of rents, then it would be possible to develop a sound basis on which to analyse an appropriate split of residual profits. It is the lack of ability to readily identify a consistent source of residual profit in the downstream that results in the difficulty in determining how residual profits should be split.

6.3 Options for reform

The Role of PRRT in tax contributions of LNG Industry

PRRT is an industry specific, secondary resource tax, that is designed to apply once projects have achieved a certain return. The primary return to the community, as with all other economic activity in Australia, is via the corporate income tax system.

In thinking about the appropriate return to the community, it is important to consider the combined impact of income tax, which is often paid early in project lifetimes, before projects have become cash flow positive, and PRRT which is often paid later in project lifetimes after projects have earned a minimum return. The combined marginal rate of tax once PRRT starts being paid is 58 per cent of income *within* the PRRT ringfence (reflecting the policy position that PRRT is deductible for corporate income tax purposes).

In suggesting changes, Treasury has sought to provide options which balance:

- impacts on existing projects, those approved but not yet constructed and investment decisions for projects that are yet to be sanctioned;
- uncertainty of future oil and gas prices and demand;
- ensuring that the PRRT continues to operate as a tax which applies once the project has achieved a commercial return; and
- ensuring an appropriate return to the community for the exploitation of its resources.

The PRRT operates differently for large scale gas and LNG projects than it does for oil projects. Oil projects generally require less infrastructure, reach peak production very quickly with an early production spike, followed by a long production tail. As a result, they become cash flow positive and pay back the initial investment relatively quickly. LNG projects have long lead times, high construction costs and long construction periods. Production is often limited to what the infrastructure can process, resulting in relatively consistent production levels (that is, there are no early production spikes). These factors result in longer payback periods before a project becomes cash flow positive and even longer periods before they make the required level of return to pay PRRT.

Any change to the GTP that attributes more of the economic rent to the upstream than the current settings is likely to bring forward revenue and increase tax payments once PRRT is payable from LNG projects. However, even significant GTP changes are not likely to bring revenue forward more than a few years, and if LNG prices are low for an extensive period, then projects may not pay PRRT at all.

Modifying the GTP Regulation

The review of the GTP Regulation has shown deficiencies in the regulations including:

- The 50:50 profit split allocation to upstream and downstream operations.
- The exclusion of exploration expenditure and development costs from the upstream cost base.
- The upstream part of the business bears all the project loss in the event of low LNG prices but receives only 50 per cent of the profits when LNG prices are high.

These deficiencies in the GTP Regulation lead to an inappropriate over-allocation of rents to the downstream operations. Treasury considers that there are two options that Government should consider that would allocate appropriate rents to the upstream operations. The first option is to replace the RPM with a netback-only method. The second option is to retain the RPM with a revised profit split and fix the existing asymmetries in the method. Both options are outlined further below.

Option 1 - A netback only method

The netback method is widely used in taxation and commercial settings for resource valuation at a mid-point in the value chain where there are no commercial transactions occurring. It represents a better basis for a safe harbour because it addresses the inappropriate assumption that the downstream functions of liquefaction, transport and marketing consistently generate economic rents in all cases, and thus removes the risk of gas owned by the Australian community being under-priced. It will ensure that the above normal profits attributable to the gas resource are brought back into the PRRT tax net by attributing all of the residual profits to the upstream activity.

To ensure project participants can continue to plan with certainty, the netback method can be based on the existing model and the way the projects have been designed to this point. That is, the value-add of downstream activities should continue to be appropriately recognised through a statutory commercial return.

If the netback only method is adopted, it is implied that the current rate of return provided in the RPM is sufficient to provide a suitable commercial return for the notional downstream entity under a netback methodology, which does not provide for a sharing of project losses. This rate of return should be extended to operating expenditure as well, to ensure a commercial return is received for all downstream costs before PRRT is payable. The current rate should be retained for the following reasons:

- The rate exceeds the statutory PRRT augmentation rate for determining whether a business is sufficiently profitable to pay PRRT.
- The return is given for the life of the project and is increased where the asset is going to be used for 15 years or less.

- Modelling indicates that some projects are already expected to use the netback price as the gas transfer price under certain price scenarios.⁶⁷ In such situations an increase to the netback rate of return would result in lower PRRT payments than the existing system.

In circumstances where a taxpayer can demonstrate that above normal profits relate to downstream functions, it would be open to them to continue to be able to approach the ATO and agree adjustments to the netback method to take account of such returns through an APA. One of the existing attractions of the current RPM is that by providing an overly generous safe harbour, it removes the need for companies to commit resources to valuing the various contributions of their functions and assets to the project and avoid disputes with the Commissioner about that analysis. In practice, this has resulted in a high degree of certainty for industry to undertake investment decisions but has come at the longer-term cost of reduced PRRT revenue for Government.

A significant drawback of moving to a netback only approach is that there is potential for multiple companies to approach the ATO for an APA with a view to demonstrating economic rents are attributable to the downstream activities of their LNG projects. This may increase the compliance burden for taxpayers and administrative burden for the ATO, particularly to the extent it involves experts on both sides to settle an approach or as part of protracted litigation. Set out below (section 6.5) are a number of principles Treasury has developed to guide future APA interactions with a view to minimising these burdens in the event the netback only method is adopted.

RPM augmentation rules inappropriately inflate capital costs

It will be necessary to fix several identified problems to ensure that the downstream contribution to the LNG production is not overvalued.

In order to calculate how much capital cost is allocated to a particular year, capital costs incurred for a unit of property over several years (section 39 GTP Regulation) and capital costs incurred before the production year (section 40 GTP Regulation) are uplifted. As noted above, there are possibly two ways of interpreting the augmentation rules. One interpretation is that the uplift applies to the final cost of the unit even if most of the expenditure is incurred in later years. Another way is the costs that are incurred in each year between the start of construction and the final cost is augmented, and the total is included as the final cost. It is the later approach that has been adopted by industry in applying these rules. The capital costs are augmented at the same rate as the capital cost allowance – currently LTBR + 7 percentage points, which is higher than the general PRRT augmentation rate.

In the RPM the higher augmentation rate is not problematic as it applies to both the upstream and downstream notional entities in the same way. In the case where a netback only approach is used, the current rules result in the overvaluation of the downstream contribution.

If a netback only approach is adopted, then the augmentation rules should be clarified to ensure that the costs incurred during the start of construction of a unit property until the final cost year is augmented each year (the year the cost is incurred) and the total of these amounts be included as the final cost for that unit of property. Treasury recommends the augmentation rate prior to production should be consistent with the general PRRT augmentation rate, i.e., LTBR + 5 percentage points.

⁶⁷ As noted in chapter 3, the netback price is adopted under the current settings when it falls below the cost-plus price. In this case, there are no residual profits.

Recommendation 2:

If a netback only approach is adopted, reduce the augmentation rate for the construction and pre-production time periods to the general PRRT augmentation rate to reflect that the methodology should not compensate investors with commercial rates of return on assets during the pre-earnings phase.

Option 2 – Retain RPM but modify profit split and fix the existing asymmetries in the model

As noted above, requiring a taxpayer to seek an APA to demonstrate a consistent source of economic rent resides in the downstream could represent a significant compliance burden for taxpayers and be resource-intensive for the Commissioner of Taxation.

The existing APA process can be a complicated, expensive and time-consuming process. The agreement lasts for a limited period of time and needs to be consistently renegotiated with the ATO over the long life of such projects. In our experience, the outcomes are not generally agreed on a timely basis, meaning taxpayers are operating with ongoing uncertainty for an extended period of time.⁶⁸

This issue is amplified when the economic rent is not significant or is only there for a limited period of time. An alternative to moving to a netback method would be to attribute some allocation of rent to the downstream activities as a safe harbour, subject to fixing the asymmetries that result in the contribution of the resource owner being undervalued and change the profit split to a ratio that reflects that significant economic rents are not consistently generated in downstream activities in all projects at all times. This would provide a safe harbour pricing method that recognises there are potentially economic rents in the downstream activities but without requiring every taxpayer to demonstrate it.

An 80:20 profit split would allow for recognition of limited rents in downstream operations while operating as an appropriate safe harbour. The split would provide a reasonable balance between the trade-off of acknowledging that downstream functions may contribute to the generation of economic rents in some circumstances, with the possibility that industry participants may face costs and uncertainty if they are required to demonstrate that particular downstream functions do generate economic rents. In some cases, these costs could be significant, both for the taxpayer and the Commissioner of Taxation, particularly as it is likely to involve the commissioning of experts on both sides to settle issues in dispute. An 80:20 profit split would also moderate the impact of the PRRT on new investment, compared to the netback only approach.

The choice about whether to opt for the modified RPM as the safe harbour is a matter for Government. On the one hand, adopting a revised profit split may still provide a tax benefit to a number of industry participants who do not generate economic rents in the downstream part of their project, particularly if resource prices are high over the medium to longer term. On the other hand, a revised profit split may impact less on the economics of existing, recently sanctioned and new proposed projects as well as reducing the potential for protracted and costly APA disputes between taxpayers and the Commissioner of Taxation that may arise with the adoption of the netback only method. If a revised profit split is adopted, then the scope for APAs should also be reduced to a

⁶⁸ PwC, Submission to the GTP Review, p 9-10.

relatively narrow group of circumstances primarily aimed at giving practical effect to the default methodology.

Given the significance of the proposed changes, Treasury has not proposed changes to the rate of return in the cost-plus or netback of LTBR + 7 percentage points. This is despite the PRRT settings which indicate an appropriate calculation of rent should approximate something equal to or less than LTBR + 5 percentage points. Treasury recommends that as the industry develops and models emerge of standalone downstream owners who both do and don't assume ownership of the gas at the taxing point, that the netback rate of return be benchmarked against these business models to determine whether the rate is appropriate for an infrastructure owner, who takes ownership of the gas between the taxing point and when the LNG is sold.

Option 3 – Cap the use of deductions for LNG projects

Options 1 and 2 are designed to address the undervaluation of the underlying gas resource in the existing GTP Regulation, particularly if LNG prices are high. However, Treasury acknowledges that neither option is certain to substantially increase revenue from the offshore LNG industry in the medium term. Some existing projects may not be sufficiently profitable to pay any PRRT over their project lives, particularly under lower oil and gas prices, unless accompanied by broader changes to the PRRT settings to address the large stock of carry-forward deductions accumulated by the LNG industry as a result of historically high uplift rates applicable prior to 2019.⁶⁹

Treasury also acknowledges that new LNG investments may be more sensitive to Options 1 and 2. This is because projects under development, such as Scarborough, Crux and Barossa, and future possible projects such as Browse, are expected to have lower upfront construction costs than the LNG projects constructed last decade, given their use of existing downstream infrastructure.⁷⁰ In addition, they will not generally benefit to the same degree from the historically high uplift rates, changed in 2019 in response to the Callaghan Review.

LNG projects in Western Australia and the Northern Territory play an important role in domestic supply. In Western Australia, LNG projects underpin the majority of the State's domestic gas supply. In the Northern Territory, they supplement domestic supply when there are disruptions to regular sources of gas. Investment in new LNG projects will support continued supply to these markets as other sources of energy diminish, and, in turn, support the transmission to lower-emissions energy production. LNG expansion projects also provide important employment opportunities for skilled workers and have spill-over effects to the state and territory economies.

Accordingly, consideration has been given to an alternate reform outside of the GTP rules, involving a cap on the use of deductions for the offshore LNG industry to some proportion of assessable PRRT receipts, with PRRT paid on the remaining amount. Treasury has considered the impact of the deductions cap on both existing and future investments. For those projects already producing or which have commenced construction, the cap should be designed in a way where it can be managed by joint venture participants within existing cash-flows at reasonable price levels. While the cap is sensitive to realised prices for petroleum, it needs to take into account cash-flows at both the low and high end of price cycles. Cost overruns on some existing projects means they may face high break-even costs. For new projects, the deductions cap can be factored into planning, but still needs to be

⁶⁹ While uplift rates were reduced in 2019 in response to the Callaghan Review, much of the pre-existing deductions for the LNG industry had already matured to substantial sums.

⁷⁰ The Scarborough project also includes an expansion of the Pluto LNG facility, or Pluto 2.

set at a level where the combined impacts of company tax, the deductions cap and the usual operation of the PRRT result in an appropriate government share while still supporting investment.

On balance and taking into account the role of a deductions cap in bringing forward PRRT, Treasury considers that setting the cap at 90 per cent of total PRRT assessable receipts is appropriate. A cap of this magnitude would equate to PRRT payable equivalent to 4 per cent of assessable PRRT receipts (tax paid on 10 per cent of revenues at the 40 per cent PRRT rate), which is relatively modest. A cap of 90 per cent largely retains the current structure and operation of the PRRT as a rent tax, while adapting the PRRT to include a minimum return for the recovery of the natural gas resources owned by the Australian community, regardless of the prevailing LNG prices. This takes into account the particular economics of LNG projects and addresses some of the concerns with the current operation of the PRRT as it applies to LNG projects.

The option considered incorporates a seven-year grace period to allow time for new projects to recoup upfront construction costs before the cap applies, designed to balance securing a minimum PRRT return with the economics of new LNG projects.

Deductions denied under the cap would be carried forward and uplifted at LTBR. This uplift rate would avoid excessive compounding of deductions and reduce the risk of a net reduction in PRRT receipts in the longer-term, relative to a higher uplift rate.

As the cap would also function as a minimum return on the recovery of Australia's natural gas, it would be inappropriate to apply the cap to projects that are already making a minimum contribution via royalty and excise arrangements. As discussed in chapter 4, when the NWS project was brought within scope of the PRRT in 2012, certain transitional arrangements were introduced at the time to ensure recognition of past capital investment as well as the significant royalties and excise that the project pays. In recognition of these factors the deductions cap should not apply to either starting base expenditure or resource tax expenditure to ensure it does not apply to the NWS project in practice.

In order to avoid the cap applying in a way that incentivises projects to close down early, the deductions cap should not apply to closing-down expenditure under the PRRT. This would preserve the full refundability of closing-down expenditure against prior PRRT liabilities.

Assuring ongoing integrity - Effective lives of assets are able to be changed

Projects can apply a special formula for the annual allocation of capital costs where they initially expect an asset to have a life of less than 15 years. This formula effectively provides higher rates of return than LTBR + 7 percentage points. If businesses subsequently elect to extend the life of assets beyond 15 years, no adjustments are required to be made.

This treatment poses an integrity risk as projects can (where asset lives are extended) change the expected operating life to beyond 15 years after benefiting first from the higher rate of return. It is recommended that projects be required to make an irrevocable election to use the shorter or longer asset life formula. Where the shorter life formula is elected, this change will restrict the period of annual allocations for the capital allowance to the operating life of the unit, but no more than 15 years.

Treasury recommends proceeding with this change both if the RPM is retained or a netback only method is adopted.

Recommendation 3

Require projects to make an irrevocable election to use the shorter or longer asset life formula to remove the integrity risk that projects change the operating life of capital projects to benefit from higher rates of return allowable under the shorter asset life formula.

Fixing the asymmetries of the RPM

If the RPM is retained, Treasury recommends proceeding with recommendations 3, 4 and 5 to ensure the ongoing integrity of the GTP Regulation. It would be important not to proceed with recommendation 2, as this is appropriate only if moving to a netback only GTP method.

Recommendation 4

Include appropriate exploration and development costs in the upstream cost base, with an appropriate way of bringing very old expenditure to current values. This could be achieved by applying the GDP deflator to original expenditure.

Recommendation 4 addresses the concerns identified in section 6.2 above that the existing cost-plus calculation undervalues the contribution of the upstream business because it excludes exploration and other early development costs involved in the recovery of gas.

Recommendation 5

Equalise the treatment of the notional upstream and downstream entities between loss situations and profit situations.

Recommendation 5 will ensure project losses are split in proportion to the sharing of economic rents, correcting the asymmetry identified in section 6.2 above.

It should be noted that in addition to opposing change to the GTP method, industry participants did not support the changes proposed in recommendations 2 to 5, primarily on the basis that the issues in question were previously considered as part of the Arthur Andersen co-design process, with the resultant “fit-for-purpose” GTP Regulation remaining fit-for-purpose.

Other approaches considered

Moving the PRRT taxing point for LNG to point of third-party sale

Treasury has considered removing the need for artificially pricing sales gas by moving the taxing point to the end of the LNG value chain. This option would be a fundamental change to the design of the PRRT for LNG projects. Making this change to existing projects would be difficult from a record keeping perspective and would be a retrospective change to the design of the tax. Making this change to new projects only would be highly complex and likely unsustainable because of the interaction between new and future projects and combinations.

Given the significance of this change to existing policy settings, the impacts on project economics and the practical difficulties of implementation, we have not recommended this option.

6.4 Comparable Uncontrolled Price method

The comparable uncontrolled price (CUP) shadow pricing method is recognised internationally as the best practice transfer pricing valuation methodology when available. When available, CUPs represent an objective arm's length price that is relevant and comparable to the circumstances of the transfer to which it is applied.

Under the current GTP rules, in order for a price for sales gas to be accepted as a CUP, the Commissioner of Taxation must be satisfied that:

- it was obtained for a sale in a market relevant to the transaction, and
- it was an observable arm's length price, allowing for reasonably accurate adjustments.

At the time the regulations were developed, there was no competitive market in Australia for feedstock (sales) gas. However, the option for determining a CUP was included in the regulation, reflecting its advantages as a means of determining an accurate gas transfer price. The power to determine the existence of a CUP was given to the Commissioner of Taxation.

It remains challenging to apply a CUP in current market conditions as there are no realistic observable third-party transactions for LNG operations in North-Western Australia. While this is not expected to change markedly in the near future, LNG operations have long lives, and we see benefits in retaining this best practice option for potential use or consideration in the future.

Improvements to CUP methodology

The current CUP rules have some inconsistencies with the OECD guidelines.

When considering a CUP one of the factors that the Commissioner needs to be satisfied of is currently the market the gas is sold into. This is narrower in scope than in the OECD guidelines which allows all reasonable conditions of a comparable transaction to be considered.

We recommend updating the CUP rules to fix any inconsistencies with the OECD guidelines. This could be achieved by including the OECD principles in the regulations:

- Contractual terms of the transaction.
 - In the context of the GTP rules, this could include volumes traded, discounts, exchange exposures, foreign currency terms, period of the arrangements, timing and terms of delivery (at the taxing point), shipping, insurance, and other relevant terms and conditions that would reasonably be considered to affect the price.
- Functions performed by each of the parties to the transaction, taking into account assets used and risks assumed, including how those functions relate to the wider generation of value by the taxpayer (and the broader multinational enterprise group to which it may belong), the circumstances surrounding the transaction, and industry practices.
- The characteristics of property transferred, or services provided (for example, the composition of the feedstock gas).
- The economic circumstances of the parties and of the market in which the parties operate.

- This could include characteristics of relevant market, for example size of markets, extent of competition in markets, relative competitive positions between buyers and sellers, extent of substitute goods and services, levels of supply and demand in the market as a whole and in particular regions; extent of government regulation, level of operation; availability of other resources (upstream) or other downstream facilities); customer the LNG is sold to.
- Business strategies pursued by the parties (how the enterprise uses innovation, degree of diversification, assessment of political changes, market penetration schemes, other factors affecting daily conduct of business).

This would supplement and build on the factors outlined in the regulations.

Recommendation 6

Update the comparable uncontrolled price (CUP) rules to align with the OECD guidelines. In particular, the analysis for the CUP should be broadened to consider all reasonable conditions of a comparable transaction. Reasonably accurate adjustments would continue to be permitted.

6.5 Advance Pricing Arrangements

In the context of the regulations, the APA is an agreement between the Commissioner of Taxation and a taxpayer that establishes an agreed method to calculate the amount of assessable PRRT receipts for the sales gas in an integrated LNG operation for PRRT purposes.

While APAs are typically used in cross-border international dealings to manage transfer pricing risks, in the PRRT context, the main aim of the APA is to find agreement on the appropriate method, assumptions and information to calculate the gas price at the PRRT taxing point.

It also provides flexibility to consider specific, and possibly unique, facts and circumstances of a particular taxpayer and what independent enterprises would reasonably have done in similar circumstances.

Industry has informed us that the APAs that are currently in place are based on the safe harbour method.

Beyond indicating that the APA must specify (1) the terms of the agreement; (2) how assessable receipts of the participant are to be calculated; (3) conditions under which the arrangement will apply, the regulations do not outline factors that the Commissioner and industry participants must consider.

The 2005 explanatory statement outlines that ‘An APA may adopt a specific methodology, several methodologies, a mixture of commonly used methodologies (as the RPM does), or some other methodology or methodologies. Without limiting the scope for other methodologies to be used, the gas transfer price delivered by a CUP (where it exists) and by the RPM methodology is to be considered in setting an APA for the purpose of the regulations.

Improvements to APAs

The current framework is designed so that if taxpayers have unusual circumstances or downstream operations that generate greater than normal profits, then they can enter into a specific arrangement with the Commissioner, through an APA, to apply an agreed method to value the sales gas at the taxing point.

If the existing RPM is replaced with a less generous netback method, this may increase the demand for APAs by industry participants to achieve a better outcome than what is provided by the default methodology.

One option which is in line with the current setting is for APAs to continue to be available as a pricing option for all taxpayers in all circumstances and with the scope of an APA not being limited in any way. A consequence of this is that it would allow industry participants to effectively relitigate PRRT rules on a case-by-case basis, through complex, intensive and bespoke APA negotiations. The potential for disputes and litigation would increase. Protracted APA negotiations and disputes would be a source of uncertainty to taxpayers, the administrator and the community. This could be costly both from an administrative and revenue perspective.

Valuation based agreements are subjective by their nature and are often based on the differing views of multiple experts of which there is a limited pool. There is the risk that expert opinions will differ and be the source of protracted disputes. A way of limiting this risk is through a robust statutory framework for determining the sales gas price and clear guidance on what methodologies are available.

A second option for APAs is to clarify their role in the system and restrict their use to ensure the proper functioning of the default methodology. Limiting APAs in this way would mean they would present fewer administrative or revenue risks but would result in industry participants being unable to depart from the default methodology, unless there was an agreed CUP between the participant and the Commissioner of Taxation. Given that CUPs are unlikely to exist in the foreseeable future, this would result in all industry participants being limited to using the new default methodology.

If a netback only approach is adopted, Treasury's preferred option is to retain the use of APAs but limit their use to specific circumstances so that they are available to taxpayers that can demonstrate that economic rents are being consistently generated by downstream activities. An example of this is where the liquefaction processing, plant and equipment used to liquefy the sales gas incorporates technology that contains unique and valuable intangible assets owned by the notional downstream entity which leads to a significantly lower cost of production of compared to other LNG projects, and the notional downstream entity is not separately rewarded through the receipt of licence/royalty payments. APAs would not be available to modify or alter other parts of the settings.

In these circumstances Treasury proposes the following high-level principles to guide the formulation of an APA between the Commissioner and a participant in an integrated project:

- An APA is based on the assumption that the economic rent is primarily attributed to the underlying resource
- An APA between a taxpayer and the Commissioner establishes a methodology to determine a sales gas price between related parties in an integrated LNG operation for PRRT purposes
- An APA may alter the default methodology to provide an additional return to the downstream activities where a project participant is able to demonstrate the existence of a unique and valuable intangible that creates economic rents in the downstream function
- The taxpayer would have to demonstrate that the unique and valuable intangible is not being sufficiently rewarded by the default methodology and that the unique and valuable intangible is owned and exploited by the notional downstream entity. It is inadequate for the entity to show that these parts of the LNG value chain merely 'add value' to the product
- The APA must specify the term of the arrangement. It should be for a period supported by the information provided to reach the agreement

- The taxpayer would need to make an irrevocable choice specifying the effective life of the downstream assets
- To the extent the taxpayer has, or can reasonably obtain access to, information that is relevant to calculate the sales gas price, this source information should be relied upon to arrive at the sales gas price
- The APA must specify the conditions under which the APA is to apply. An APA can only be valid if certain critical assumptions hold and so outcomes remain within a contemplated range or context.

An APA would not be available for:

- Proposing market valuation or other transfer pricing methodologies or other industry pricing models not provided for in the Regulations
- Other than altering the netback method to allow for unique and valuable intangibles owned and exploited by the notional downstream entity, the APA cannot be used to propose an alternative method
- Expanding the allowable costs under the default methodology
- Altering the netback rate of return for any asset beyond what is required to compensate the unique and valuable intangibles owned and exploited by the notional downstream entity
- Attribution of a higher return to the downstream based on a high level of integration, the joint assumption of risks between the upstream and the downstream, or the exposure of the downstream to upstream supply risk
- Justification of a higher return for the downstream based on assumptions that downstream infrastructure would be able to extract rents from the upstream because the upstream is dependent on the downstream
- Attribution of additional value to a downstream asset or contract arrangement that results in a more efficient operation because the asset was constructed at a lower cost than competitors or service contracted at a lower rate than competitors.

If a modified RPM is adopted, then the use of an APA should be limited to circumstances where they are required to give practical effect to the statutory residual profit split. This is because an 80:20 profit split allows for appropriate recognition of limited rents in downstream operations.

Recommendation 7

Modify the Advance Pricing Arrangement (APA) rules to provide guidance to industry and the Commissioner of Taxation on the principles that the Commissioner must have regard to in agreeing an APA.

If the RPM is retained, the use of an APA should be limited to circumstances where it is required to give practical effect to the statutory residual profit split.

6.6 Transparency and simplicity

Current transparency measures within the PRRT regime include the annual *Report on entity tax information* published by the ATO on data.gov.au, which shows the names of all the entities that have paid PRRT in each year and the amounts paid. The ATO also publishes PRRT tax gap data which estimates the difference between the amount that the ATO collects and what it would have collected if every taxpayer was compliant with the law.⁷¹ As part of the annual release of the corporate tax transparency data the ATO releases information that provides contextual information in the corporate tax transparency report.

A key issue raised in most submissions from community groups was a desire for greater transparency within the GTP rules, with the aim of providing the Australian community with confidence that it was receiving an adequate return for its gas resources.

While the ATO may have sufficient visibility into the operations of major players in the LNG industry, there is a distinct lack of public visibility and transparency which will continue to undermine public confidence that the Australian community is getting a fair return.⁷²

[A] lack of transparency undermines the public's ability to judge for itself the probity and value of transfer pricing arrangements. Many of the firms involved in offshore gas exploration and extraction in Australia have a long track record of using transfer mispricing – as well as other aggressive tax planning strategies...⁷³

[B]usinesses should be required to publicly report on the price of gas at the taxing point and show reasonable calculation details.⁷⁴

The industry view, on the other hand, was that the community's confidence in the efficacy of the PRRT regime is best served through ATO compliance activity, noting the ATO's existing powers to ensure compliance and increased understanding of the LNG industry means it is effective in monitoring industry activities.

⁷¹ See <https://www.ato.gov.au>. For 2019 20, the net PRRT gap is estimated to be \$13 million (1.3%). The ATO identified that the main drivers of the gap related to the inherent complexities of the PRRT system.

⁷² Tax Justice Network – Australia, Submission to the GTP Review, p.9

⁷³ Professor Richard Eccleston and Mr Lachlan Johnson, Institute for the Study of Social Change, Submission to the GTP Review, p.2

⁷⁴ Dr Diane Kraal, Submission to the GTP Review, p.14.

The further release of information by the ATO without important supporting contextual information has the potential to cause more confusion rather than providing clarity...

... 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 were required to publicly release price or cost information.⁷⁵

Increasing transparency and simplicity

The PRRT, and especially gas transfer pricing, is inherently complex. Whereas royalty and excise arrangements have been recognised as easier to administer and a more transparent means of demonstrating to the community that it is getting a return for the development of its resources, transfer pricing specialists may be required to apply the GTP Regulation and, similarly, the ATO requires specialist expertise to administer the PRRT system.

Given the inherent complexity, Treasury tends to agree with the industry view that the release of further information would not improve transparency for the general public unless it is accompanied by detailed explanatory information, significantly increasing compliance burdens. Moreover, requiring companies to release the gas transfer price and accompanying calculation details may be damaging to the commercial interests of LNG companies. Information about the GTP calculations is not currently released because they rely on contractual arrangements and internal costs that would usually be commercial-in-confidence information.

There is a fundamental difference between the visibility the ATO has over the appropriate gas transfer price companies arrive at and the information that should be disclosed to the public. Treasury is confident the ATO is able to access the information it needs to provide assurance to the Australian Community that the appropriate GTP price is calculated and the right amount of PRRT is collected. The reform of the current GTP rules should enhance transparency for the ATO, while the revised APA process ensures the ATO has visibility over companies' claims of any economic rent residing in the downstream part of their respective LNG production.

A balance needs to be struck between commercial in confidence information and transparency. Publishing gas transfer prices would potentially create scenarios where commercial information could be reconstructed.

As such, additional transparency measures are not recommended at this time.

6.7 Start date of application

We recommend that the proposed changes to the GTP Regulation apply to all LNG projects subject to PRRT as soon as possible and ideally from 1 July 2024. Given that this is a pricing methodology and to give effect to the way the PRRT is supposed to operate, it would be appropriate to apply the same

⁷⁵ APPEA, Submission to the GTP Review, p. 41-42.

treatment across all LNG projects regardless of when they commenced. The Regulation is scheduled to sunset on 1 April 2026, and is required to be remade.

Delaying changes until the Regulation sunsets, will result in the existing pricing mechanism impacting future revenues, and potentially result in delayed and overall lower PRRT collections.

Further, as new fields are developed there will also be significant interaction between these fields and existing projects, through tolling and combination certificates and use of existing infrastructure. In these circumstances it would be distortionary to provide significant differences in pricing methodologies across projects.

If the deductions cap is adopted, we recommend a start date of 1 July 2023 or 7 years after the year of first production, whichever is later.

7. How the GTP rules should apply to new fields using existing infrastructure

Most LNG projects in Australia have historically been designed as integrated joint venture projects with the same ownership of the resources, the upstream extraction and downstream liquefaction infrastructure. However, future upstream developments are expected to use existing downstream infrastructure as far as possible to maximise economic returns. At the same time, downstream operators seek new upstream supply to backfill and extend the productive life of their liquefaction infrastructure. Where there are different ownership interests for the upstream and downstream parts of projects this will require a tolling arrangement.⁷⁶ In some circumstances this may involve linking new fields to an existing commercial project and processing the gas as if it were part of the original project.

7.1 Tolling

Although there are references to tolling type arrangements in the original explanatory materials, and it may be possible for the existing rules to apply to tolling arrangements, the problems previously identified with the assumptions underpinning the development of the RPM are even more pronounced when it comes to tolling.

The current RPM allocates economic rents to downstream functions conducted by the petroleum companies even if they are not generating them via those activities. If the existing rules applied to tolling arrangements, they would attribute residual profits to functions the companies may be outsourcing and not undertaking.

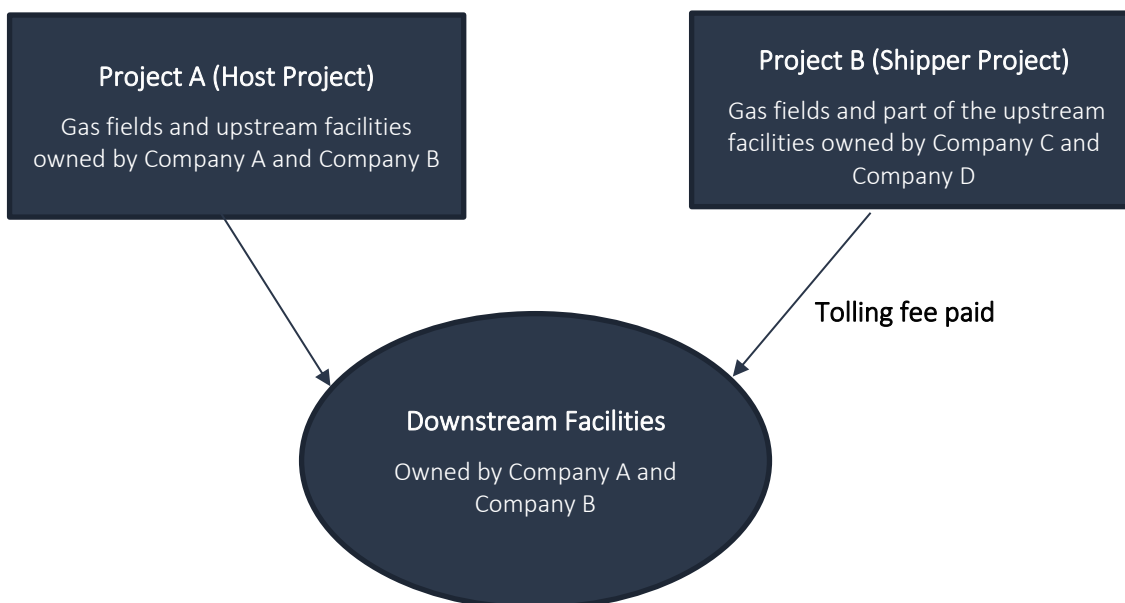
The approach to tolling should reflect the broader approach to reduce the assumed economic rents in the downstream. Additionally, it should reflect the actual amount paid by the resource owner for activities they have outsourced such as processing and liquefaction.

Principles of a tolling arrangement within a netback calculation

Tolling arrangements will vary depending on the ownership structure of the upstream and downstream facilities of the LNG project. In many projects, the taxing point of the sales gas is within the liquefaction plant, and so a portion of the toll fee will be related to the upstream PRRT project and a portion to the downstream facilities. Apportionment principles are discussed further below. The treatment for tolling does not cover an arrangement where the gas was sold at or prior to the taxing point.

⁷⁶ Tolling arrangements can be complex arrangements depending on the ownership structure of the entities involved. There are circumstances where the tolling arrangements will include other payments in addition to a tolling fee. The design of provisions in the regulations should consider incorporating a broad definition of a tolling payment.

Below is a simple example of a tolling arrangement.



In the example above involving two PRRT projects, Project B (Shipper Project) is paying a tolling fee to Project A (Host Project) to have its gas processed and transformed into LNG.

Treasury recommends that in circumstances where a third-party toll paid or a commercially driven price is reached through joint venture negotiations to process the sales gas into LNG, that this amount should be included in the calculation of the GTP for the entity paying the toll. In working out the netback price the following components would apply for the shipper project/person paying the toll:

Netback price = (LNG price) – (transport cost if relevant) – (marketing cost) – (proportion of the tolling fee that is allocated to the downstream processing)

This arrangement would be consistent with the principle that the PRRT should be calculated on the basis that the costs are attributable to the owners of the gas.

There may be some situations where there is common ownership in both the petroleum project and the liquefaction plant by one or more companies. In these cases, a test should be developed to determine whether there is enough commercial tension between the two groups of owners to be confident that the price is arm's length/commercially driven.

The strong preference of the petroleum Industry is that tolling arrangements continue to be subject to the current GTP Regulation as reflected in the RPM. However, as outlined above, the case for attribution of residual profit in the downstream is weaker in a tolling arrangement than in a fully integrated project. Like an integrated project, tolling reflects a deliberate decision by the resource owner to retain ownership of the gas rather than sell it to a third party and as such it would not be appropriate to assign significant economic rents to the downstream 'marketing' function or for the risk inherent in owning the resource through the downstream phase. As a result, Treasury recommends that the default methodology applied to tolling arrangements is the netback only option, where no residual profit is allocated to the downstream.

Principles of tolling in the RPM calculation

If the Government were to retain the RPM for integrated projects, the same approach should be applied to tolling projects in recognition that tolling type arrangements are more sensitive to PRRT changes due to their lower capital expenditures requirements and that they should not have fundamentally different tax settings that will change how companies decide to design their projects.

This recommendation is consistent with the Terms of Reference for the Review which asked for advice on:

- 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

If the RPM is retained, then it is recommended that in circumstances where an arm's length or a commercially driven price is paid to process the sales gas into LNG then this amount be included in the RPM calculation for the entity paying the toll. As the RPM method attributes costs to the cost-plus calculation (upstream costs) and the netback calculation (downstream costs) the toll paid will need to be reasonably apportioned. Working out the RPM the following components would apply for the shipper project/person paying the toll:

- Cost-plus price = (upstream capital costs) + (upstream operating costs including proportion of the arms-length tolling fee that is allocated to the upstream processing).
- Netback price = (LNG price) – (transport cost if relevant) – (marketing cost) – (proportion of the arms-length tolling fee that is allocated to the downstream processing).

Recommendation 8

Update the regulations for tolling arrangements in alignment to support the effective operation of the RPM and to ensure that arm's length/commercial transactions for parts of the LNG production chain (that reflect the underlying resource ownership and risks to parties) are used as far as possible as a reference for establishing a gas transfer price.

Insufficient evidence and anti-avoidance provisions

Where there is insufficient evidence that the toll paid is an arm's-length price/commercially driven price, the netback price should be calculated using the process in section 25 of the GTP Regulation:

- (i) The taxpayer and the Commissioner agreeing on the netback price; or
- (ii) Where an agreement on the netback price cannot be reached, when the Commissioner is satisfied that a fair and reasonable price can be worked out using information available to the Commissioner.

In line with the Government response to Recommendation 12 of the Callaghan Report that supports amending PRRT anti-avoidance rules, anti-avoidance provisions should apply in circumstances where entities structure the tolling arrangement to artificially shift value to the Host Project or artificially shift the toll fee either to the upstream or downstream part of the project.

Recommendation 9

Update both the PRRT general anti-avoidance rule and the arm's length rule and put beyond doubt that they apply to the GTP Regulation. This follows a recommendation made by the Callaghan Review that the Government amend the PRRT anti-avoidance rules to be in line with the income tax anti-avoidance rules.

Commercial tension test

Due to the significant economic investment in LNG projects, it is common for there to be joint venture operations with more than one entity having an interest in the project. Joint venture agreements vary. However, standard clauses often include:

- (i) The percentage share interest in the project which includes the resource, the upstream assets and/or downstream assets.
- (ii) The percentage share interest in expenses and liabilities.
- (iii) The rights and duties of the operator of the project.
- (iv) The decision-making process such as the composition of an Operating Committee, the matters that require approval from an Operating Committee and the voting rights of each party.

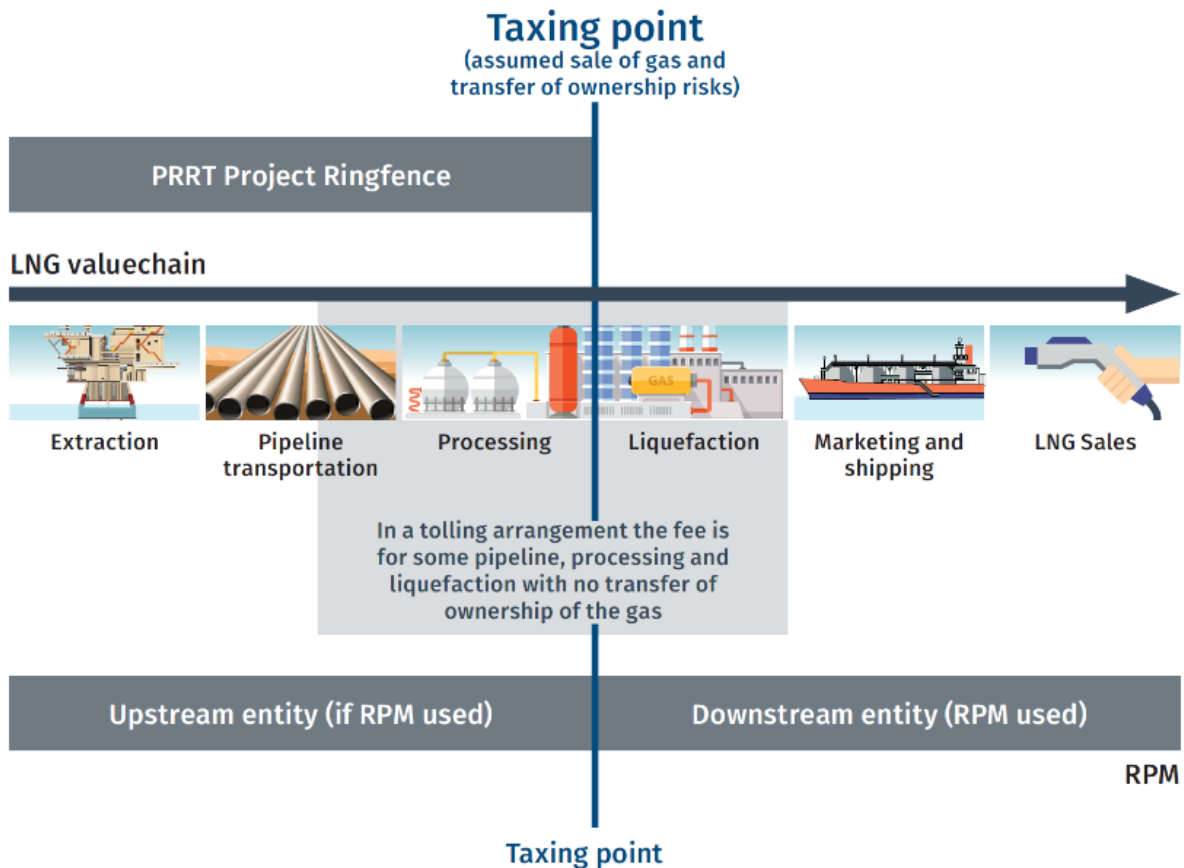
The commercial context that led to the tolling price should be factored in when determining whether it is an appropriate amount to include in the GTP calculation. It may be reasonable to include such an amount in circumstances where the parties to a tolling arrangement are third parties and each party has influence in negotiating the terms of the arrangement.

In considering whether an arms-length price/commercially driven price has been paid in a tolling arrangement, an objective test that allows companies to determine whether there was sufficient commercial tension should be used. Principles that could be included in the test are:

- (i) Each taxpayer of the Host Project and the Shipper Project needs to demonstrate the toll charged is an unrelated third-party toll or calculated by reference to an unrelated third-party toll.
- (ii) Each party of the Host Project and the Shipper Project can demonstrate that any common ownership between the two projects did not control the terms of the tolling agreement. That is, through each party having voting rights or negotiation powers in the respective projects.
- (iii) When considering common ownership this includes affiliated entities or associated entities of either the Host Project or the Shipper Project.
- (iv) If an entity and its affiliated entities/associated entities has the power of veto and the entity controls the business decisions of the project, then there isn't sufficient commercial tension between the entities.
- (v) There is no evidence of any of the parties working together to reach an agreed tolling price.

Treatment of Upstream and Downstream portions of a tolling fee if netback only option is adopted

In many projects the taxing point of the sales gas is within the liquefaction plant. This means that even where the toll arrangement is only for the processing and liquefaction facilities, a portion of the toll fee will be related to the upstream PRRT project and a portion to the downstream facilities. In some instances, a toll fee may also include an amount for use of upstream infrastructure such as pipelines that transport the gas to the LNG facility. The toll fee may be charged for multiple MPCs which are processed through the upstream infrastructure.



When a liquefaction plant owner enters a tolling agreement, they may also be required to spend money either optimising their existing infrastructure for the new gas or building new infrastructure to manage the new volumes. Under the existing PRRT framework, the upstream component of a liquefaction plant may be part of an existing petroleum project.

There are various options for the treatment of the upstream and downstream portions of the tolling fee:

- Option 1: reasonable apportionment with the upstream component of the toll included in the PRRT ringfence when the liquefaction plant is linked to a petroleum project.
- Option 2: creation of a separate petroleum project for each tolling arrangement the host enters into.
- Option 3: treat the toll for a plant that includes liquefaction as part of the downstream of both the host and shipper projects.

Treasury recommends the adoption of option 1 for reasons outlined below.

Option 1 - Recommended option: reasonable apportionment with the upstream component of the toll included in the PRRT ringfence when the liquefaction plant is linked to a petroleum project

Apportionment of toll fees when Host Project and Shipper Project are both PRRT Projects

Treasury's recommendation is that when the Host Project and the Shipper Project are both PRRT projects, the following method is used to apportion the arms-length toll paid into upstream and downstream components:

- (i) The Shipper Project would claim the upstream portion of the toll paid as a general deduction and the downstream portion of the toll paid would be included in the netback calculation.
- (ii) Where the infrastructure used is part of an existing PRRT project, the Host Project would treat the upstream portion of the toll as an assessable tolling receipt. Any modifications to the upstream plant would likewise be deductible to the host project. The downstream portion of the toll would not be an assessable tolling receipt and the Host Project includes the operating costs and capital costs for the downstream infrastructure in the netback calculation.

Apportionment of toll fees when infrastructure owner is not a PRRT Project

There are examples of tolling arrangements where the infrastructure owner is not a PRRT Project. This would occur when they do not have an interest in an offshore exploration permit, retention lease or production licence. Where the Shipper Project is a PRRT Project it is recommended that where a reasonable method has been used to apportion the arms-length toll paid into the upstream and downstream components of the project, the toll payment can be treated in the following way:

- (i) The Shipper Project would claim the upstream portion of the toll paid as a general deduction and the downstream portion of the toll paid would be included in the netback price calculation.
- (ii) As the infrastructure owner is not a PRRT Project, the tolling payment would not be treated as an assessable receipt for PRRT purposes and there would be no deductions for any of the infrastructure. The income and deductions for the infrastructure owner would be included in the corporate income tax regime.

This treatment of the toll paid is symmetric for PRRT purposes as the PRRT taxable profit for Shipper Project would be calculated as follows:

(Assessable receipts based on the netback price) – (Deductible expenditure associated with the upstream such as wellheads, pipes, exploration and proportion of the tolling fee that is allocated to upstream processing)

There would be no PRRT income or deductions for the infrastructure owner for the toll fee or the infrastructure.

Option 2: Tolling receipts to be treated as a separate PRRT project

Treasury considered this option as PRRT is a project-based tax, but in recognition that current industry trends make it likely that the same infrastructure will be used over multiple projects.

This option would ensure tolling receipts received by the Host Project are treated as a separate PRRT project. It would ensure that tolling arrangements are not entered into or negotiated in a way that shifts value from a new PRRT project to a Host Project that has carried forward losses (that is, are not yet in a PRRT paying position). Such arrangements could be used to shield the PRRT attributable to one project from the losses relating to another project.

This option would add significant complexity to the regime and lift the regulatory burden with every infrastructure owner in every tolling arrangement being required to create a separate nominal project including pure infrastructure owners who previously had no PRRT obligations. It would create a complex interaction with the key components of the PRRT Act such as how the taxable profit would be calculated for this project and how closing down expenditure would be apportioned and refunded. It would also create different treatment for different types of infrastructure owners with similar principles applying to other types of infrastructure such as pipelines.

Instead of recommending this approach, Treasury's recommendation, consistent with the Callaghan Review, is to strengthen the anti-avoidance provisions in the PRRT to ensure that the anti-avoidance provisions apply in circumstances where entities structure the tolling arrangement to artificially shift value to the Host project by artificially shifting the toll fee either to the upstream or downstream part of the project.

Option 3: No apportionment of liquefaction fees, as allocated to the downstream

A long-standing issue in the PRRT has been the sharing of commercially sensitive information between companies that is required for tax purposes. The need to apportion a tolling fee between upstream and downstream builds on the existing design of the PRRT and the obligation to apportion the plant and equipment across the project and share that information between the owners of the infrastructure. Apportionment of the tolling fee will require both the shipper and host project to agree on the apportionment of the toll to ensure that the tax symmetry outcome is met.

Treasury considered treating a toll relating to a liquefaction plant as a wholly downstream toll for the purposes of removing the additional valuation point and need to share potentially commercially sensitive information between infrastructure owners and those accessing the infrastructure. This option would be to have no apportionment of the tolling fee and to treat any arm's length price paid for a tolling service that includes liquefaction as part of the downstream. This would remove the need to apportion the upstream component of the toll fee and treat it as an assessable receipt or deductible expenditure.

Such an approach would also alleviate the potential for mismatches between assessable income and deductible expenditure in both the host and shipper projects. It would also ensure that there is no difference in treatment for liquefaction plants based on whether they are linked to petroleum projects.

In practice, this would shift the taxing point to an earlier point of the process for tolling projects. The toll fee may still need to be apportioned to account for multiple commodities still in the process at that point. For example, where the tolling arrangement includes part of the onshore facilities where the gas stream includes multiple commodities such as domestic sales gas, Liquid Petroleum Gas (LPG) and condensate. As a result, it may not achieve the simplicity or remove the requirement to share information.

Feedback provided from industry participants throughout the Review's consultation process revealed a preference for Option 1 and a commitment to share the relevant information, rather than to proceed on the basis of Option 3. Treasury agrees with this approach.

Treatment of Upstream and Downstream portions of a tolling fee if RPM is retained

If the RPM method is retained then it is recommended that where a reasonable method has been used to apportion the arms-length toll paid into upstream costs and the downstream costs, then the toll paid be used in the RPM calculation.

Apportionment of toll fees when Host Project and Shipper Project are both PRRT Projects

When the Host Project and the Shipper Project are both PRRT projects, a reasonable method is used to apportion the arms-length toll paid into upstream and downstream components:

- (i) The Shipper Project would claim the upstream portion of the toll paid as a general deduction and would include this as an operational cost in the cost-plus price of the RPM. The downstream portion of the toll paid would be included in the netback calculation.
- (ii) Where the infrastructure used is part of an existing PRRT project, the Host Project would treat the upstream portion of the toll as an assessable tolling receipt. Any modifications to the upstream plant would likewise be deductible to the host project. The downstream portion of the toll would not be an assessable tolling receipt. The Host Project includes its operating costs and capital costs for the RPM calculation.

Apportionment of toll fees when Infrastructure owner is not a PRRT Project

Where the infrastructure owner is not a PRRT project, and a reasonable method has been used to apportion the arms-length toll paid into the upstream and downstream components of the project the toll payment can be treated in the following way:

- (i) The Shipper Project would claim the upstream portion of the toll paid as a general deduction and include this as an operational cost in the cost-plus price of the RPM. And the downstream portion of the toll paid would be included in the netback price calculation.
- (ii) As the Infrastructure owner is not a PRRT Project, the tolling payment would not be treated as an assessable receipt and there would be no deductions for any of the infrastructure. The infrastructure owner would not be required to complete the RPM calculation as they are a PRRT Project. The income and deductions for the infrastructure owner would be included in the income tax regime.

Recommended Principles for tolling arrangements

Below is a summary of the recommended principles for tolling arrangements:

1. Where an arm's length price/commercially driven price is paid for a tolling service that includes liquefaction, in the netback-only option the toll should be included in the netback calculation for the Shipper Project. And in the retained RPM option the upstream component of the toll should be included in the cost-plus price and the downstream component in the netback price.
2. Where the Host Project (person owns the infrastructure) and the Shipper Project (person purchasing tolling services) are both PRRT projects, a reasonable method is used to apportion the toll paid with the upstream toll included in the PRRT project and treated as operating cost in the cost-plus price for the retained RPM option. The downstream component of the toll is included in the netback price for the Shipper project.
3. Where the infrastructure owner is not a PRRT project, the toll payment would not be treated as assessable revenue and there would be no deductions for the infrastructure as PRRT does not apply to the infrastructure owner. The Shipper Project would be required to use a reasonable apportionment method for the toll with the upstream component being included in the PRRT project and the cost-plus price for the retained RPM option. And the downstream component in the netback price.
4. Where there is no arm's length/commercially driven price the netback will be calculated using the process in section 25 of the GTP Regulation.
5. The determination of whether a tolling fee is arm's length/commercially driven should be based on an objective test involving a list of relevant factors, including being able to demonstrate that the common ownership between two joint venture projects does not give those entities control of the terms in the tolling agreement and that each party to the agreement has voting rights or negotiation powers in the respective projects. The Commissioner should have the power to determine whether a toll is arm's length.

The result is that where an arm's length tolling transaction for LNG processing occurs, Treasury recommends this should be used by the shipper project to calculate the gas transfer price for either the netback only option or a retained RPM option.

- **For netback only option** the netback price (arm's length toll exists) = (LNG price) – (shipping cost) – (marketing cost) – (tolling fee).
- **For the retained RPM option** the cost-plus price (arm's length toll exists) = (upstream capital costs) + (upstream operating costs including proportion of the toll paid allocated to the upstream processing). The netback price would be the calculated as noted above.

Where no arm's length toll is present, the current practice of either making agreed adjustments with the Commissioner, through the APA process, or where an agreement cannot be reached a fair and reasonable price, using information available to the Commissioner, being worked out should continue.

- **For the netback only option** the netback price (no arm's length toll) = (LNG price) – (shipping) – (marketing) – (agreed amount or fair and reasonable price for processing to be included).

- **For the retained RPM option** the cost-plus price (arm's length toll exists) = (upstream capital costs) + (upstream operating costs including an agreed amount or fair and reasonable price for the processing). The netback price would be the calculated as noted above.

7.2 Combination of PRRT projects

In some circumstances a joint venture may seek to leverage its existing infrastructure by incorporating new fields into the existing commercial project. Companies may combine these new fields commercially and treat them as one project. However, for PRRT purposes, each new petroleum field is reflected in the issuance of a new production licence, and its associated incremental upstream infrastructure is treated as a separate PRRT project unless a combination certificate is provided by the Minister for Resources. As future developments are prioritising using the infrastructure of existing LNG projects this may lead to the increase in LNG Projects applying to be combined and treated as a single project for PRRT purposes.

The benefits of combining the projects are:

- Expenditure/losses that have been incurred in the existing LNG infrastructure are able to be offset with assessable receipts earned in the new gas field development.
- Practical administrative benefits of including all the assessable receipts and expenses in the one PRRT tax return.
- Removal of requirements to trace how much each field is contributing to the hydrocarbons measured at key points in the project.

Entities that hold an interest in two or more petroleum projects can apply for a combination certificate from the Minister for Resources where the projects are sufficiently related to one another.

The criteria considered are:

1. the operations and facilities of the petroleum projects
2. the entities that carry on or provide the operations and facilities of the petroleum projects; and
3. the geological, geophysical and geochemical features of the production licence areas in relation to the petroleum projects.⁷⁷

At the time when PRRT was first enacted the explanatory memorandum provided an example for the third criteria being, where two production licences entitle the licence holders to recover petroleum from the same discrete petroleum pool. However, as consideration is given to all three criteria in determining whether the projects are sufficiently related to one another it may be possible for two or more production licences to be combined where the same infrastructure is being used by the same production licence holders for completely different fields.

When the NWS Project was included in the PRRT regime the provision on combining projects was amended to ensure that it was not able to be combined with any other project. This provision was

⁷⁷ <https://www.industry.gov.au/sites/default/files/issue-of-combination-certificates-guideline.pdf>

amended to ensure that the starting base expenditure could not be used to shield other offshore petroleum projects from its PRRT liability.

It is appropriate to ensure that resource owners who develop new fields using their own infrastructure are not advantaged by the existing tax arrangements. New discrete fields should have similar tax arrangements regardless of whether they use a tolling model or are otherwise incorporated into project infrastructure. It is proposed that the project combination rules be revisited to ensure they do not apply in circumstances where the expansion of LNG projects involves the extraction of resources from discrete new fields. This is consistent with the PRRT being a project-based tax.

Industry has submitted as part of this Review that if projects were not able to be combined:

'...there are several practical and administrative difficulties and technical difficulties in how the RPM will operate, including:

- Production from each individual field will need to be tracked separately;*
- Currently, when products are sold, sales are not allocated to each individual field, but treated as one. Without project combinations, 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 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 uncertainty in tax lodgement positions due to the additional complexities;*
- Taxpayers IT systems will need to be redeveloped, significantly increasing the cost of compliance.⁷⁸*

The current GTP Regulation requires the identification and allocation of operating and capital expenditure to multiple phase points and to multiple petroleum products. The ability of industry to apply the current GTP Regulation would appear to demonstrate that the administrative burdens outlined by industry may need to be confirmed through further consultation.

The developments in technology and the infrastructure being used for multiple LNG projects was not contemplated when the criteria for the combination of petroleum projects was established. Treasury recommends the project combination rules be revisited to strengthen the requirement for new resources to be treated as separate projects and to prevent losses associated with one project from being offset against revenue from another field. The administrative and practical issues raised by industry should also be considered when making these changes to the project combination rules.

⁷⁸ Chevron, Submission to the GTP Review, p 3.

Recommendation 10

The project combination rules should be revisited with a view to strengthening the requirement that the new field have some relevant geological or geochemical connection to the existing project.

7.3 LNG facilities entering the PRRT system

Another aspect where the current GTP Regulation is not clear is the basis of the capital cost to be used where an LNG facility that is not currently subject to PRRT enters the PRRT regime for backfill purposes.

As part of the changes to the GTP method, Treasury recommends updating the regulations to use historical cost of the LNG facility, uplifted by the GDP deflator to the date of first production.

Any incremental expenditure necessary to prepare the facility for gas from the new backfill PRRT project, such as a new train or other costs, would be treated as new expenditure consistent with other new expenditure under the netback approach.

This approach is attractive as it has a verified cost, does not include the risk of valuing the resource within the asset and is consistent with cash flow tax principles.

Where historical cost information is unavailable to a purchaser, section 25 of the GTP Regulation will be used to determine the amount to include in the netback price.

Recommendation 11

Update the GTP Regulation to ensure that where an LNG facility enters the PRRT regime (either just for the purposes of the GTP Regulation or for broader PRRT calculations) for the first time for backfill or tolling purposes, the value of the plant for use in PRRT calculations is the historical cost of the LNG facility, uplifted by the GDP deflator to the date of first production for PRRT purposes.

8. Impacts on PRRT revenue and investment

8.1 Modelling approach

Treasury has undertaken scenario analysis on the impact of changes to the PRRT, including changes to the GTP Regulation, for the five major offshore LNG projects. This analysis incorporates the main features of the PRRT system, including the carry-forward of undeducted expenditure at the varying rates applying to different categories of expenditure, the ordering of deductions and the GTP settings. The model also incorporates policy changes in the PRRT in response to the Callaghan Review, including the lower rates applying to carry forward expenditure.

Impacts have only been modelled for existing PRRT LNG projects that are in production. The NWS LNG project has been excluded given its ongoing royalty payments and unique tax arrangements that largely eliminate the possibility that it will pay PRRT.⁷⁹

Assumptions about project revenues and costs over the modelled period are based on data from Wood Mackenzie, Treasury forecasts, and supplementary information from the ATO.

Estimates of PRRT revenue are highly sensitive to assumptions for key economic parameters, such as oil prices. For the purposes of illustrating this sensitivity, we have carried out scenario modelling using three different oil price assumptions: a US\$72.70 per barrel West Texas Intermediate (WTI) oil price (central price scenario), US\$92 per barrel WTI (high price scenario) and \$US62 per barrel WTI (low price scenario). Under all three scenarios, oil prices are indexed by CPI beyond 2026-27.

As Treasury is not privy to the actual commercial arrangements between the joint venture participants, there are many project-specific features that Treasury's modelling may not accurately capture, including:

- contract sales prices for petroleum products;
- deviations of actual planned forward expenditure, maintenance schedules and production levels from those assumed by Wood Mackenzie; and
- unique arrangements within or between PRRT projects/project partners that differ from modelled assumptions.

The modelling contained in this report should not be interpreted as the equivalent of a budget costing. As in the Callaghan Review, the modelling presents estimated impacts of policy options on PRRT receipts only. The modelling does not take into account other interactions with the tax system, such as deductibility of PRRT payments against company tax. The modelling for some options incorporates additional recommendations of this Review as set out below.

8.2 New baseline for LNG projects

In 2017, under a long-run oil price assumption of US\$65 per barrel Brent (indexed to a 2 per cent CPI), the Callaghan Review modelling indicated total PRRT revenue to be \$12 billion over the 10 years to 2027, and \$106 billion over the period to 2050. For the medium-term, the projection included PRRT

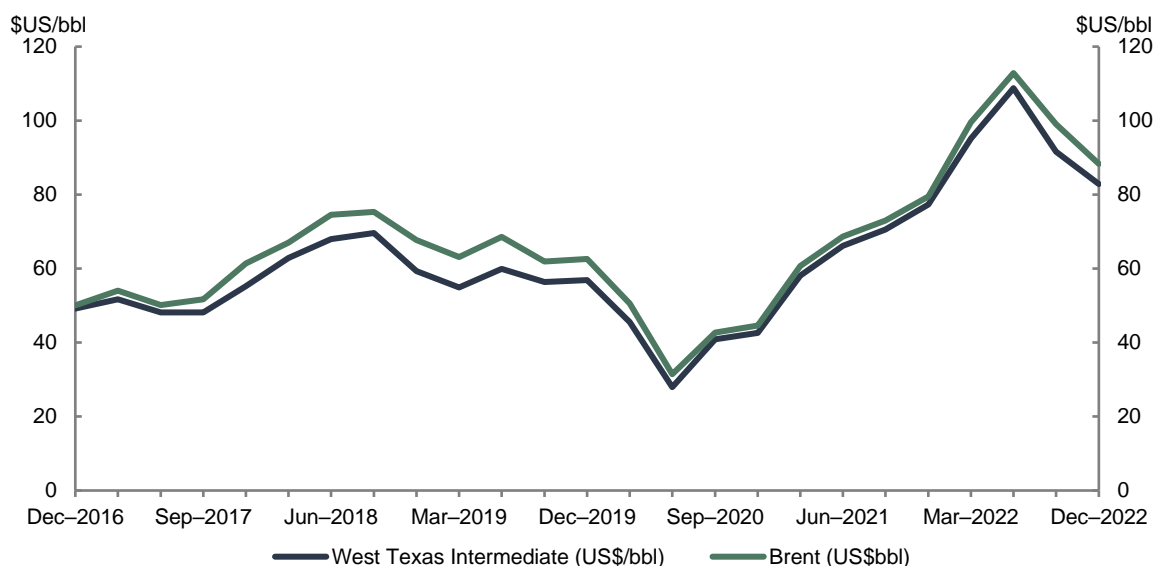
⁷⁹ A key feature of transitioning the NWS project into PRRT in 2012 was a starting base amount that is carried forward and uplifted at LTBR plus 5 percentage points. The starting base effectively acts as a tax shield against PRRT, partly reflecting significant past and ongoing royalty and excise payments.

collections from LNG projects as well as domestic gas and oil projects. However, in the longer term out to 2050, domestic gas and oil projects were not expected to be a significant source of PRRT. Most LNG projects were expected to pay PRRT during their project life cycles.

Since the Callaghan Review, several developments have impacted the outlook for PRRT, in particular:

- Project costs have exceeded expectations. This is discussed further in Chapter Four. Higher costs in the downstream parts of the business reduce the GTP price via the netback price calculation.
- In the five-year period between the Callaghan Review and now, oil prices have been highly volatile. Although high across much of 2022, oil prices were below the Callaghan Review’s baseline oil price assumption for some of the period since 2017, which contributes to lower realised PRRT assessable receipts than expected.

Chart 8.1: Quarterly Oil Price 2017-2022



Data from Department of Industry, Science and Resources, Resource and energy quarterly: March 2023⁸⁰

As a result, most LNG projects are now not expected to pay significant amounts of PRRT before 2030. Companies are now expected to pay PRRT in respect of their LNG projects later, and overall PRRT receipts across the medium and long term will be lower than projected by the modelling undertaken for the Callaghan Review.

Specifically, under a US\$72.70 per barrel WTI oil price⁸¹ that is indexed by CPI beyond 2026-27, Treasury estimates PRRT receipts from the five LNG projects will total around \$5 billion over the period to 2033-34 and around \$53 billion over the period to 2049-50. Consistent with the design of a rent tax, oil prices below this level would extend the delay and reduce PRRT collections over the longer term, with PRRT payments not expected to pick up until the mid to late 2030s. Treasury modelling at a US\$62 per barrel WTI price (indexed to CPI beyond 2026-27) shows PRRT collections will be lower, totalling less than \$1 billion over the period to 2033-34 and around \$20 billion over the period to 2049-50.

⁸⁰ <https://www.industry.gov.au/publications/resources-and-energy-quarterly-march-2023>

⁸¹ As Chart 8.1 shows, in recent years Brent has consistently traded at a small premium to WTI.

Based on consultations with industry participants and data from Wood Mackenzie, if the oil price stays flat at US\$65 per barrel (Brent) over the long term, most existing LNG projects subject to the PRRT are expected to make overall returns on investment of less than 10 per cent. This return would not be sufficient to result in these LNG projects paying PRRT over their expected lives. As noted earlier, the PRRT recognises the capital costs of investment and allows them to be carried forward at uplifted rates until these losses have been absorbed, generally at LTBR plus 5 percentage points (equating to between 6 and 10 per cent since 2011). Similarly, the netback allows a return on downstream assets of LTBR plus 7 percentage points (equating to between 8 and 12 per cent since 2011) each year.

At a higher oil price of US\$92 per barrel WTI (indexed to CPI beyond 2026-27), Treasury modelling suggests that these projects will pay sooner and more PRRT over their lifetimes with significant revenue brought forward. PRRT collections would total about \$18 billion over the period to 2033-34 and about \$99 billion over the period to 2049-50.

In addition to the very high sensitivity of the modelled PRRT collections to oil prices, there are several other sources of significant uncertainty given the long modelling horizon. For example, the modelled outcomes are dependent on assumptions in relation to economic parameters such as exchange rates, the potential for extension of asset production lives at the price assumed, and continued global appetite for Australian LNG. In this regard, BP's *Energy Outlook 2023* forecasts considerable uncertainty for global LNG demand after 2030.⁸²

The modelling outcomes should be treated as indicative of the relative impacts of different reform options on PRRT receipts and not as net impacts on Commonwealth revenue.

8.3 Impacts of proposed changes on existing projects

The Callaghan Review included analysis that showed moving to a netback would result in:

'[I]ncreased PRRT revenue from 2023 to 2050 (totalling around \$89 billion) with a particularly strong increase between 2027 and 2039 (totalling around \$68 billion).

This outcome is achieved by increasing the transfer price in cases where there are residual profits, and allocating associated residual profits 100 per cent to the upstream to be taxed at 40 per cent, while allowing a return of LTBR plus 7 percentage points to the downstream. The higher revenue is from a combination of: projects that were already paying PRRT in the baseline scenario, paying a higher amount of PRRT sooner; and projects paying PRRT that were not paying PRRT in the baseline scenario.'

Treasury modelling indicates that a change to a netback only approach will no longer produce revenue impacts of this magnitude. The decrease in the revenue baseline flows through to estimates of additional revenue that would follow GTP rule changes (whether it be adopting a netback only approach or modified RPM).

The Treasury modelling below for the 'netback only' approach incorporates modelled impacts of the following complementary changes recommended in this report: providing an additional downstream operating cost to the netback calculation and reducing the augmentation of pre-production capital expenditure from LTBR + 7 percentage points to LTBR + 5 percentage points. In addition, the modelling results presented below for the 'modified RPM' approach also incorporate the inclusion of exploration expenditure into the cost-plus calculation and equalising the RPM split under both profit

⁸² See <https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/energy-outlook/bp-energy-outlook-2023.pdf>

and loss as recommended in this report. The modelling of a deductions cap does not incorporate any of the other GTP recommendations that could be implemented alongside a cap. The modelling covers five major offshore LNG projects and assumes that the changes to the GTP rules would commence from 1 July 2024.

Treasury modelling shows that the PRRT gains are higher for a netback only approach than for a modified RPM in a range of oil price scenarios. A GTP change to netback only would still mean that existing projects do not pay PRRT until after they have received a minimum return of 7-8 per cent on total upstream project spend (compounded annually) and a minimum return of 9-10 per cent on downstream.

At the US\$72.70 per barrel WTI oil price (indexed to CPI beyond 2026-27), the netback only option is estimated to raise an additional \$3.9 billion in PRRT collections over the period to 2033-34 and \$16.3 billion over the period to 2049-50. By contrast, the revised RPM is estimated to raise an additional \$2.4 billion in PRRT collections over the period to 2033-34 and \$10.2 billion over the period to 2049-50.⁸³

At a lower oil price of US\$62 per barrel WTI (indexed to CPI beyond 2026-27), Treasury estimates there is very little additional PRRT gain over the period to 2033-34 from changing to a netback only approach. This is because the existing RPM allows for the netback price to be used when it falls below the cost-plus price. Under the lower oil price scenario, most projects are assumed to be using a netback price already and so the change to the netback only approach raises negligible additional PRRT, estimated to be about \$3.3 billion over the period to 2049-50. This is consistent with the assumptions in the current uplift rates and netback rate of return for PRRT purposes that assume there are no rents to be taxed in a project that is generating lower returns.

At this lower oil price, the revised RPM is estimated to raise very little additional PRRT over the period to 2033-34 and approximately \$6.2 billion over the period to 2049-50. This is higher than the estimated PRRT collections under the netback only option as the shared losses under the revised profit split results in higher gas transfer prices.

Conversely, at higher prices the netback only approach is estimated to result in higher PRRT collections over a longer period from these existing projects than a revised RPM. In the US\$92 per barrel WTI oil price scenario (indexed to CPI beyond 2026-27), the netback only approach is estimated to result in an additional \$21.9 billion of PRRT collections over the period to 2033-34 and \$48 billion over the period to 2049-50, whereas the revised RPM is estimated to result in an additional \$13.3 billion of PRRT collections over the period to 2033-34 and \$26.4 billion over the period to 2049-50, reflecting a lower attribution of residual profits to the upstream when prices are high (relative to the netback back only approach).

Treasury's assessment is that existing projects will not become uneconomic as a result of either change to the GTP Regulation. Existing projects are continuing to operate at returns lower than industry expected when they invested. Most existing projects are not expected to pay PRRT for a number of years, even with the changes, and are only likely to pay PRRT if they become more profitable over the long term. Existing projects are likely to make a range of investment decisions over the next few years to ensure stable supply to their LNG plants. The recommendations in this report on

⁸³ Note: The PRRT receipts impacts of changes to the Gas Transfer Pricing regime in this chapter are presented in gross terms and do not consider the estimated reduction in company income tax payable resulting from higher PRRT receipts. PRRT payments are deductible for company income tax purposes. Therefore, an increase in PRRT receipts is expected to be partially offset by a decrease in company income tax receipts, as additional company income tax deductions become available.

tolling and combinations seek to ensure that those decisions are made on the best *economic* case for development rather than the best *tax* case for investment.

Treasury modelling shows that a deductions cap option is expected to bring forward PRRT receipts relative to the baseline under each oil price scenario, particularly over the period to 2033-34. Consistent with the intent of the deductions cap, longer term impacts to 2049-50 are lower compared with the changes to the GTP arrangements, but PRRT receipts are still higher compared to the baseline over this period. For most LNG projects the deductions cap operates as a bring forward of PRRT, while for some others it may represent a minimum payment to the Australian community for the natural resource.

A deductions cap would begin generating PRRT receipts immediately. At the US\$72.70 per barrel WTI oil price (indexed to CPI beyond 2026-27), it is estimated to raise an additional \$7 billion over the period to 2033-34 and \$3.7 billion in total over the period to 2049-50.⁸⁴

At a lower oil price of US\$62 per barrel WTI (indexed to CPI beyond 2026-27), Treasury estimates an additional \$8.1 billion gain to PRRT receipts over the period to 2033-34. This is because, at lower prices, the deductions cap will bring forward PRRT receipts from projects not expected to pay substantial PRRT over the medium term. Over the longer term to 2049-50, there is a smaller increase in PRRT receipts (\$3.0 billion in total), compared with the central US\$72.70 per barrel WTI oil price scenario.

At higher prices, the deductions cap is estimated to result in less of an increase in PRRT receipts over the medium term compared with the lower and central price scenarios. This is because, under current arrangements, projects will pay PRRT earlier under a higher oil price, and hence the cap has less of a role to play in bringing PRRT revenues forward. In the US\$92 per barrel WTI oil price scenario (indexed to CPI beyond 2026-27), the deductions cap is estimated to raise an additional \$5.6 billion in PRRT receipts over the period to 2033-34 and \$3.8 billion over the long term to 2049-50.

Table 8.1 Estimated change in PRRT receipts from five major offshore LNG projects

Price scenario	Oil Price WTI (US\$, indexed)	Policy option (impact on PRRT receipts* to 2033-34, \$m)		
		Netback only #	Modified RPM # (80:20)	Deductions cap (90%, LTBR uplift, 7-year grace period)
High	\$92	21,900	13,300	5,600
Central	\$72.70	3,900	2,400	7,000
Low	\$62	200	300	8,100

* The results are the projected impact on PRRT receipts only. They are not budget costings and do not take into account the net impact on Commonwealth revenue arising from the deductibility of PRRT payments against company tax payable.

Policy options to modify the RPM incorporate additional changes to the GTP rules as set out in the text above. These changes are not included in the deductions cap option presented.

⁸⁴ Note: The PRRT receipts impacts of changes to the PRRT regime as a result of the deductions cap in this chapter are presented in gross terms and do not consider the estimated reduction in company income tax payable resulting from higher PRRT receipts. PRRT payments are deductible for company income tax purposes. Therefore, an increase in PRRT receipts is expected to be partially offset by a decrease in company income tax receipts, as additional company income tax deductions become available.

8.4 Impacts of proposed changes on new projects

Treasury notes that recommendations which increase the overall tax burden on projects also lower the internal rate of return (IRR) to investors. This could affect future investment decisions and may mean that some marginal investments are less likely to proceed, particularly if the after-tax return on an investment is less than or close to the hurdle rate set by investors. However, the PRRT tax settings should be designed to balance a fair return on natural resources for the community with investment. They should not go so far as to support projects that do not reach a risk-adjusted IRR to proceed.

Feedback from industry participants is that new projects are likely to be more sensitive to changes to the GTP Regulation than existing projects. As a result of policy changes implemented in response to the Callaghan Review, new projects do not benefit from the same uplift rates on carried-forward expenditure as existing projects. Moreover, industry indicated through consultation that new projects are more likely to use existing infrastructure than the LNG projects constructed last decade, and this may be via tolling arrangements. These types of arrangements may result in lower capital expenditure but higher operating costs that are not subject to augmentation. The combination of lower capital cost and reduced augmentation relative to existing LNG projects means these new projects are more likely to pay PRRT within 7 to 10 years, provided they do not suffer significant cost overruns on remaining capital expenditure, or long periods of low prices.

Joint venture participants continue to assess the feasibility of the new projects and argue that any change to the GTP Regulation may result in projects remaining undeveloped as it may erode project returns to below required investment returns.

We note that final investment approvals for new projects have taken place recently in the context of a more favourable price environment and outlook for the LNG industry. This is despite the 2019 changes to the uplift rates and the possibility of other changes to the GTP Regulation being signalled since the Callaghan Review.

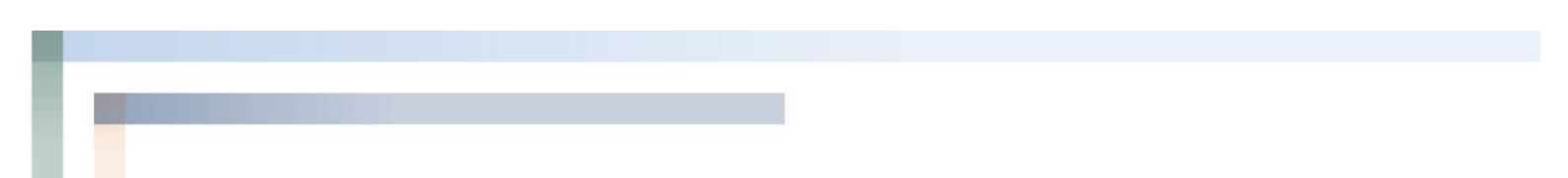
Some industry participants have shown Treasury, on a confidential basis, high level results from their own modelling that show the effect of proposed changes. Although the results were shared, Treasury has been unable to verify or test the impacts on investment described as we are not privy to underlying model assumptions. While there is no reason to doubt the impacts, it is difficult to base decisions on these results as PRRT payments are highly sensitive to assumptions, especially the assumed oil prices and project discount rates.

While moving to a netback only method may raise more revenue from future projects, it has higher economic impacts and may result in some marginal projects not proceeding. The revised RPM will likely raise less revenue from existing and new projects, but it is likely to have a lower impact on new projects, meaning a greater likelihood of projects going ahead, all other things being equal. The deductions cap is likely to have the lowest impact on investment decisions, given that new projects that meet existing commercial hurdle rates are already expected to pay PRRT within 7 to 10 years.

There is a trade-off between revenue from existing projects and from future projects that may or may not proceed for a variety of factors.

Regardless of whether the changes to the PRRT and GTP Regulation are made, if oil and gas prices were to fall and remain low it is unlikely that there will be significant PRRT revenue from LNG projects or much new investment.

If oil (and LNG) prices are consistently in the higher range, then most new and existing projects are likely to pay PRRT at some point in their project lifetimes and will be capable of absorbing changes to the GTP arrangements while still remaining profitable. In this scenario, new projects will likely meet investor hurdle rates even with changes to the GTP Regulation.



The central case scenario presents the greatest trade-off. At mid-range oil and gas prices, existing projects are unlikely to meet original investor hurdle rates but will be generating significant cash flows. Only a change to a netback only approach will result in a significant increase in PRRT receipts in this scenario. However, a change to a netback only method is more likely to result in some investments not proceeding, while the revised RPM or deductions cap could mean they still proceed. These projects would likely contribute corporate tax revenues, provide gas to Western Australia's domestic market and contribute LNG cargoes to aid the global energy transition.

The choice between the netback only approach, the revised RPM and the deductions cap should be informed by a view on the role of PRRT revenues in the tax base, likely future role for gas over the next 30 years, expectations of long-term prices driven by LNG demand and the role of Australian gas reserves in meeting that demand.

Treasury's assessment is that the GTP changes may have an impact on investment but that this is project specific and only possible to quantify at the point in time and economic conditions in which the investment decision is made. Treasury understands that tax is never a factor on its own that determines whether an investment proceeds or not, but is one of many direct and indirect inputs that contribute to a decision about whether an investment proceeds.

Ultimately it is only the individual joint venture participants who can make a judgment call about how one project compares with other opportunities in their portfolios. One of the risks for investment in Australia is even if the GTP changes are not significant enough to move the project below investment grade, the project may nevertheless be rated lower in the portfolio of opportunities than other projects.

On balance, Treasury's assessment is that, while material, a change to the RPM on its own should not be decisive against other more significant factors in an investment decision such as overall projects costs, oil price assumptions and global demand for LNG. However, when considering changes to the PRRT in the context of the broader investment environment and the importance of the sector in supporting the transition to a lower emission economy, a cap on the use of deductions may provide an appropriate balance between ensuring an equitable return to Australians for the recovery of their natural gas, while minimising disincentives to investment and new supply.