SHELL AUSTRALIA

Submission to the review of the Petroleum Resource Rent Tax

FEBRUARY 2017

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Glossary

ABR	Augmented bond rate expenditure as defined by the PRRTAA
ATO	Australian Taxation Office
CSG	Coal seam gas
FOB	Free-on-board
FLNG	Floating liquefied natural gas
FPSO	Floating production storage and offloading
GDP	Gross domestic product
GTL	Gas-to-liquids
IRR	Internal rate of return
JV	Joint venture
mmbtu	Million British Thermal Units
MPC	Marketable petroleum commodity as defined by the PRRTAA
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
LTBR	Long-term bond rate as defined by the PRRTAA
NWS	The North West Shelf joint venture
PRRT	Petroleum Resource Rent Tax
PRRTAA	*Petroleum Resource Rent Tax Assessment Act 1987* (Cth)
QCLNG	Queensland Curtis Liquefied Natural Gas joint venture
RPM	Residual pricing method as defined by the PRRTAA
Shell Australia	The Australian operations and interests of the Royal Dutch Shell plc group

Executive summary

1. Oil prices are both cyclical and volatile. The PRRT was designed in the 1980's, during a period where oil prices peaked at around $120 per barrel and fell to around $22 per barrel (inflation-adjusted). Against this backdrop, it was recognised that a resource rent tax would be the most efficient taxation system to secure a fair share of oil price upside, without discouraging marginal projects or bringing about early termination of projects as production-based taxation can do. This volatility continues – for example, over the last few years the oil price has varied from around $107 per barrel in June 2014 to as low as $29 per barrel in January 2016. The oil price is currently sitting around $53 per barrel.

2. The PRRT is operating as designed and intended. PRRT does not discourage investment because it has been designed to tax the value of the oil and gas resources and applies, albeit at a relatively high rate of 40%, only once oil and gas projects exceed a reasonable return on investment. This is appropriate due to the significant risks taken on by investors and the large amounts of capital required to explore for the resources and develop the substantial production infrastructure required, particularly for LNG projects.

3. The current design features of the PRRT ensure an equitable and practical balance between ensuring a fair return to Australia for its finite oil and gas resources, supporting the continuation of existing projects and not discouraging much-needed continued investment. In particular, oil and gas projects typically seek a risk-adjusted after-tax IRR of 15% in order to attract investment in a globally competitive market. This investment expectation applies across the investor portfolio, meaning investments in unsuccessful exploration or projects are taken into account with successful projects. The combination of the PRRT augmentation rates and transferability of exploration expenditure ensures that PRRT applies once reasonable project returns have been made.

4. It is critical that Australia maintains a globally competitive fiscal regime that does not discourage future investment. Fiscal competitiveness is influenced by the combined impact of corporate income tax and resources taxation, including the timing of tax payments compared to the timing of returns to investors. Recently announced or enacted reductions in taxation in a number of countries, including the United Kingdom and the United States, will erode the competitiveness of Australia as an investment destination.

5. The present decline in government revenues from the oil and gas industry is reflective of current global economic conditions. Low commodity prices have impacted the profitability of current PRRT paying projects. However, as stated, this short term volatility is fully accounted for within the design of the PRRT, with compensating revenue flows evident when commodity prices are high.

6. Perceptions of Government receipts being lower than some expect is further compounded by the inevitable and unavoidable gap between huge expenditure of capital during the exploration, development and construction phases and the creation of profits many years after these costs have been accounted for. The large LNG plants constructed in recent years have required tremendous capital investment, with approximately $200b required for the construction of 14 new trains of LNG production. These new projects (noting that three are still under construction) have very long expected lives, and the returns they generate for investors and governments will vary from year-to-year reflecting the volatility of oil prices and other economic factors. However, investments in these new projects will provide significant economic benefits to investors, governments and the Australian community, through taxation, employment and local procurement for many decades to come.

7. Shell has taken a long-term view of global LNG demand and sees Australia as having significant potential. In the last five years alone, Shell Australia invested more than $50 billion in Australian LNG projects and paid state and federal governments around 40% of its profits during this period. It will take many years for Shell to break even on the cost of capital invested in its new Australian projects and start to make profits. The development and operation of LNG projects is important to Australia's economic and social prosperity, but to ensure investment in existing and future projects, the forecast after-tax returns will need to be internationally competitive.

8. The unprecedented investment in Australian resources projects during the last decade should not be taken for granted. If Australia's economy is to continue to grow and prosper, it is critical that actions are not taken without a comprehensive analysis of potential impact on existing projects and future investment. Some factors that impact future investment are uncontrollable, such as oil prices, but others are clearly controllable, such as the taxes imposed on these projects. Care should be taken before pursuing policy measures that may produce short term revenue gains at the cost of jobs and economic growth from future investment in Australia's oil and gas industry.

9. Overall, Shell Australia is confident that the PRRT is not only working as originally designed and intended, but that it is being administered and complied with in accordance with the PRRTAA. Furthermore, changes to the PRRT at a time when the industry is under considerable pressure from a depressed global market will be detrimental to existing and future projects, and will undermine Australia's global competitiveness and perceived sovereign risk.

1. Introduction

Shell Australia welcomes the opportunity to make a public submission in response to the Australian Government's review of PRRT, crude oil excise and associated Commonwealth royalties. In this submission, we have addressed issues outlined in the discussion note of 20 December 2016 and have outlined other considerations that are relevant to the terms of reference of this review.

Shell Australia recognises the responsibility of the Government to ensure an appropriate return to the community on Australia's finite oil and gas resources, while supporting the creation of jobs and economic growth of our nation through the development of those resources. Revenue transparency initiatives and consultation with the community, such as this review, are key to ensuring stakeholders are well-informed. We are supportive of a fact-based discussion of the design of Australia's resources tax framework.

Shell's Australian operations generate significant government revenues through a range of taxes including those not covered by the terms of reference of this review. Despite Shell Australia having been in a heavy investment phase during recent years, direct taxes paid have amounted to around 40% of our total accounting profits during the 2011-2015 years, totaling over $3.6 billion.

The current decline in government revenues from the oil and gas industry is reflective of the current global economic conditions, commodity prices and the investment and construction phase of many new projects. The recently constructed Australian greenfield LNG projects had relatively high break-even costs when investment decisions were made many years ago. Today, they are without doubt among the highest costing LNG projects globally. The higher costs, combined with low sales prices and less favourable USD/AUD exchange rates, means that the producing projects are generating lower returns for investors and governments alike.

Shell Australia is confident that the PRRT is not only working as originally designed and intended, but that it is being administered and complied with in accordance with the *Petroleum Resource Rent Tax Assessment Act 1987* (Cth). Furthermore, changes to the PRRT at a time when the industry is under considerable pressure from a depressed global market will be detrimental to the ability of Australia's LNG projects to deliver value in the future, will undermine Australia's global competitiveness and perceived sovereign risk, and make it even more difficult to monetise Australia's vast remaining natural gas reserves that too often have proved uncommercial to develop decades or more.

In addition to this submission, Shell Australia has contributed to and supports the observations made in the submissions of the Australian Petroleum Production & Exploration Association, the Business Council of Australia and the Queensland Resources Council.

2. Shell in Australia

Shell is a global group of energy and petrochemical companies, with its headquarters in The Hague, the Netherlands. Shell operates in over 70 countries around the world and employs around 94,000 people.

Shell has been investing in Australia since 1901 and Australia forms a core part of Shell's global natural gas business. Historically, Shell's operations in Australia spanned across both the downstream and upstream sectors. However, following the sale of our refining and most retail operations to Vitol during the last few years, our operations are now focused on the exploration, development and production of natural gas.

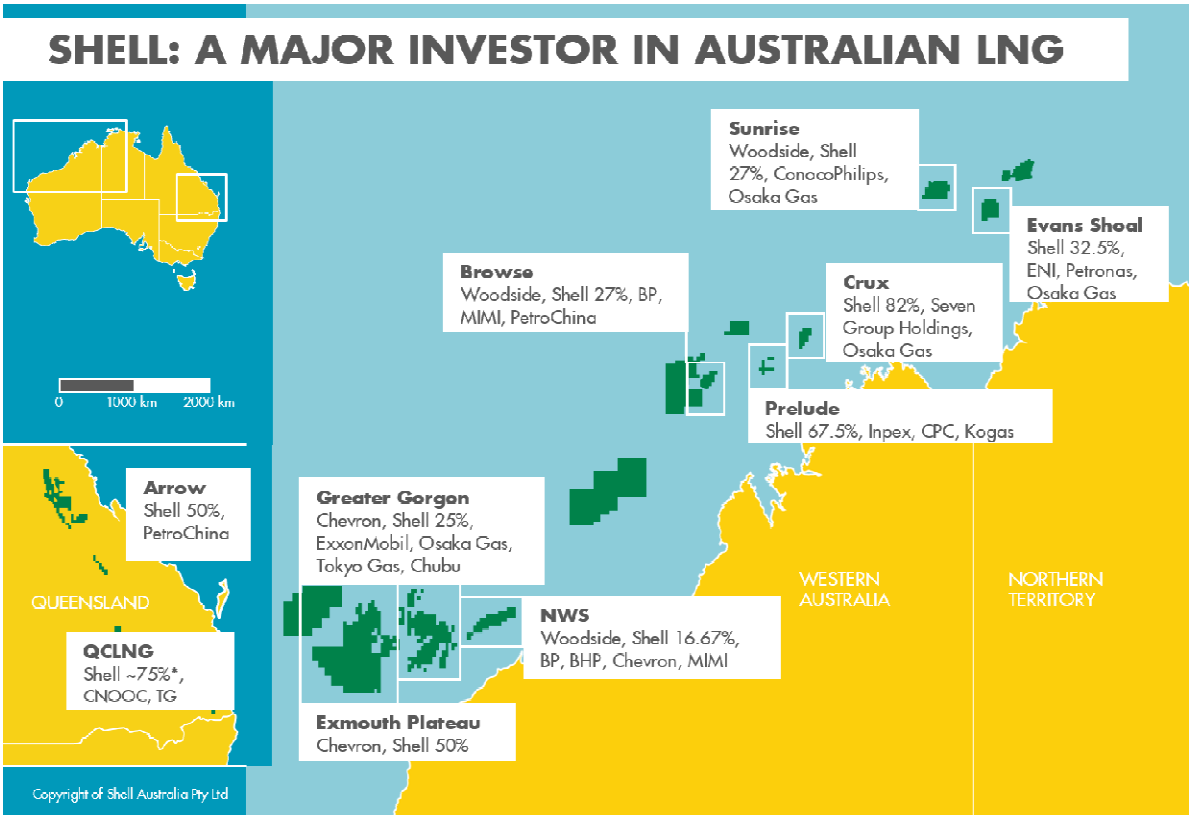
In the last five years alone, Shell has invested more than $50 billion in Australian projects – attracting one in every four dollars that Shell invests globally – making Shell one of the largest foreign investors in Australia and the country's largest natural gas resource holder. This level of investment reflects a combination of factors including the quality of Australian gas resources, the proximity of Australia to key LNG customers in Asia, and, importantly, a historically stable fiscal and regulatory framework.

Shell's major investments in Australian gas projects and applicable resource-specific taxes are as follows:

Project name	*Shell interest*	*Production start year*	*Resource taxes applicable*
NWS LNG	16.67%	1989	PRRT, excise, royalties
QCLNG	73.75%	2014	PRRT, QLD royalties
Gorgon LNG	25%	2016	PRRT
Arrow Energy Limited	50%	2004	PRRT, QLD royalties
Prelude FLNG	67.5%	Under construction	PRRT
Browse LNG	27%	Feasibility stage	PRRT, WA royalties
Sunrise LNG	26.6%	Feasibility stage	Uncertain

Shell also holds a shareholding of approximately 13.28% in Woodside Petroleum Limited and an interest in a number of exploration permits in Western Australia, Queensland and Commonwealth jurisdictions.

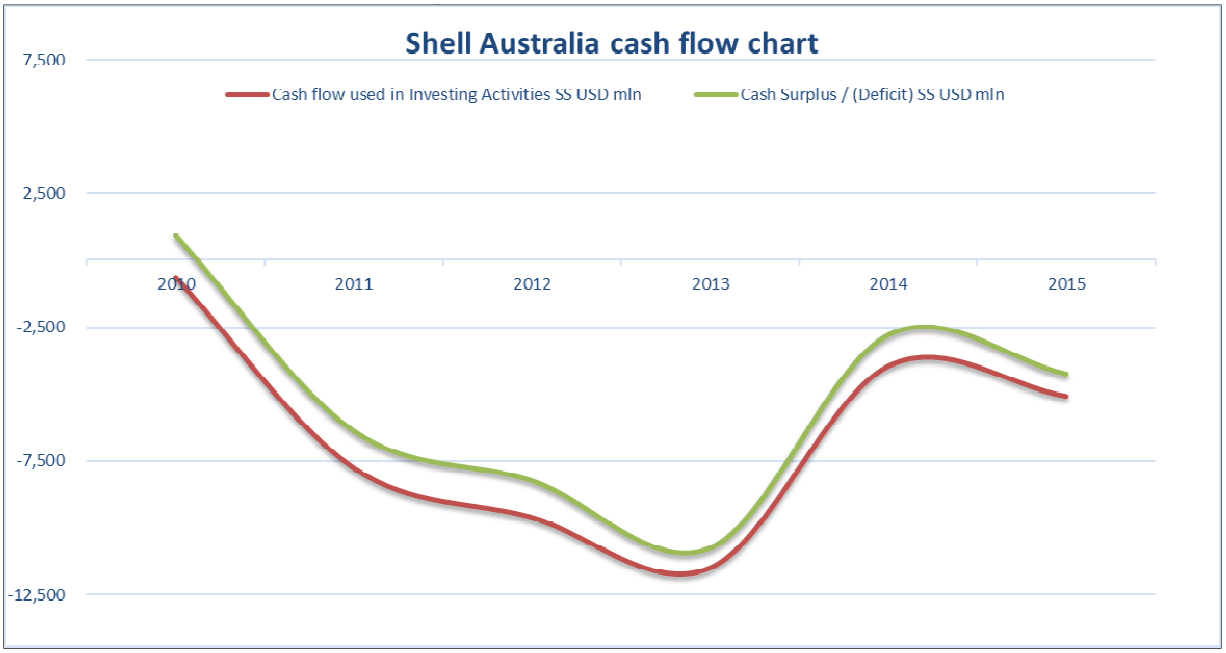
The Australian gas projects in which Shell holds interests produce large volumes of LNG for export to international customers. However, we also supply a significant percentage of the domestic gas requirements of customers in Western Australia through our interests in the NWS and Gorgon, and the east coast through our interests in QCLNG and Arrow projects.



3. Shell Australia's tax profile

Shell's Australian operations generate significant government revenues through a range of taxes including those not covered by the terms of reference of this review, such as the 30% corporate income tax. Despite Shell Australia having been in a heavy investment phase during recent years, the following direct taxes have amounted to around 40% of profits from 2011-2015.

Cash tax paid 2011 to 2015	***AUD m***
Income tax	1,602
Interest withholding tax	430
Royalties	1,097
Condensate excise	528
Others (e.g. payroll tax, duties)	459
Total direct taxes	**4,117**



The cash flow deficit position during recent years is reflective of Shell Australia having been in a heavy investment phase and is consistent with the unprecedented investment in Australian LNG projects by the oil and gas industry. All cash generated during this period was reinvested in capital projects. The large tax payments relative to Shell Australia's cash flow and profits reflect that PRRT is just one element of Australia's tax framework that applies to the oil and gas industry.

3.1 Shell Australia's PRRT position

Historically, Shell has paid PRRT in relation to Australian oil projects. However, Shell has not held an interest in an Australian oil project subject to PRRT since 2005. Since then, Shell Australia's strategy has been to focus on developing LNG projects. Shell has taken a long-term view of global LNG demand and sees Australia as having significant potential to meet this demand both domestically and internationally.

In Australia, this has meant becoming involved in the development of Gorgon and Prelude, with final investment decisions taken for the two projects in 2009 and 2011 respectively. Gorgon commenced

production in 2016, although production has been hampered by technical start-up issues. Prelude is still under construction. Shell's combination with BG in 2016 means Shell is also now a major shareholder in the QCLNG project, which commenced production in 2014.

Shell Australia does not currently pay PRRT in relation to its three producing project interests in NWS, QCLNG and Gorgon (note that Prelude is yet to commence production). There are two main reasons for this.

The first reason is that the PRRT is not the primary resource tax for the NWS and QCLNG projects. Both projects were transitioned into the PRRT regime from 1 July 2012.

- The NWS project has been subject to Commonwealth royalties since inception in 1984, and to the crude oil excise since it applied to condensate from 13 May 2008.
- Excise applies at a rate of 30% of the volume-weighted average price of condensate realised once loaded onto ships for export (the volume-weighted average realised FOB price).
- Royalties apply at a rate of between 10-12.5% (depending on the area) of the value of the gas at the point it is extracted from the ground (well-head value).
- Excise and royalties are deductible for PRRT purposes, reflecting the common purpose of these regimes to tax the inherent value of the gas resource.
- As an onshore CSG project, QCLNG has been subject to Queensland royalties since inception in 2005.
- The transition into the PRRT resulted in the recognition of a starting base for Shell Australia in relation to its interests in the NWS and QCLNG. The starting base reflects the value of the projects upon entry into the PRRT regime.
- The starting base also provides an equitable outcome that acknowledges the PRRT was not applicable to these projects at the time investment decisions were taken.

The second reason is that the PRRT is a profits-based resource tax. Profits are made once total returns have exceeded the costs of developing the resource, and Shell Australia is only now commencing to recover the significant investment to develop the Gorgon and QCLNG gas fields.

- The costs to develop Australian LNG are significant due to the sheer scale of the infrastructure required, and the time it takes to successfully evaluate, design and construct these projects once sufficient gas reserves have been discovered.
- The Gorgon LNG project commenced production 35 years after the Gorgon gas field was discovered in 1981, with significant exploration, development and construction cost incurred during this period.
- The Prelude gas field was discovered in 2007 and, 10 years later, Shell and its venture partners continue working to bring the floating LNG project online, again with significant costs accrued during this period.
- Shell Australia has invested more than $50 billion to develop Australian LNG projects during the last five years alone.

4. The Australian LNG industry

As noted by McKinsey in its 2013 report on extending the LNG boom, Australia's 'mining boom' has actually been an 'LNG and mining boom'.

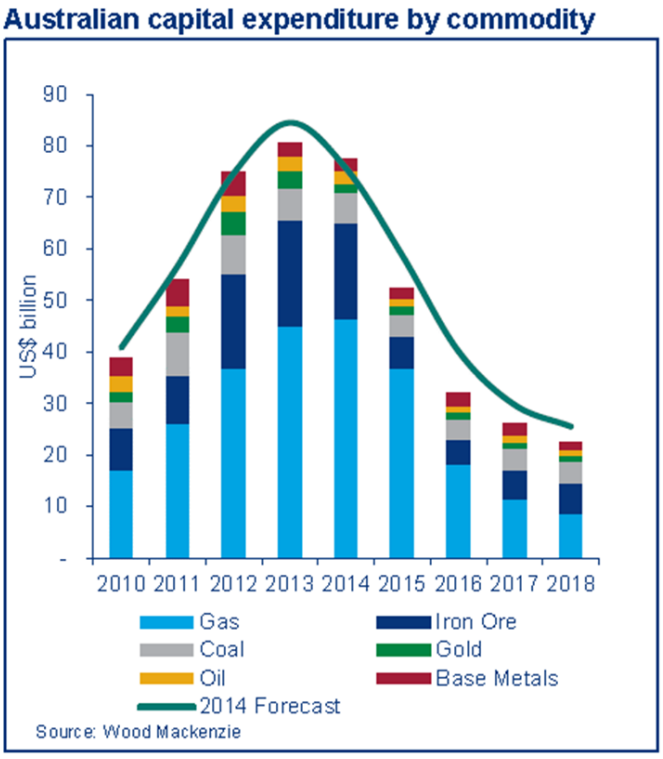
> *Australia has been very successful in attracting investment into its resources sector, which has spread wealth throughout the country. Within resources, the LNG sector has seen the largest absolute growth, attracting investment over A$200 billion in the last decade (more than the mining industry).*[1]

[1] Michael Ellis, Christiaan Heyning and Oliver Legrand, *Extending the LNG boom: Improving Australian LNG productivity and competitiveness* (2013), McKinsey & Company http://www.mckinsey.com/global-locations/pacific/australia/en/latest-thinking/extending-the-lng-boom.

Australian investment in LNG projects during the last decade was greater than any other country in the world:

- 1989: Australia had one operating LNG project producing 2.5 mtpa;
- 2015: Australia exported 30.4 mtpa with a value of $16.53 billion;
- 2018: Australia expected to overtake Qatar as world's largest exporter; and
- 2020: 10 Australian projects expected to collectively produce >85 mtpa.

Operating projects	***Projects currently under construction***
North West Shelf Venture (1989)	Prelude FLNG
Darwin LNG (2006)	Wheatstone LNG
Pluto (2012)	Ichthys LNG
Queensland Curtis LNG (2014)	
Gladstone LNG (2015)	
Australia Pacific LNG (2015)	
Gorgon LNG (2016)	

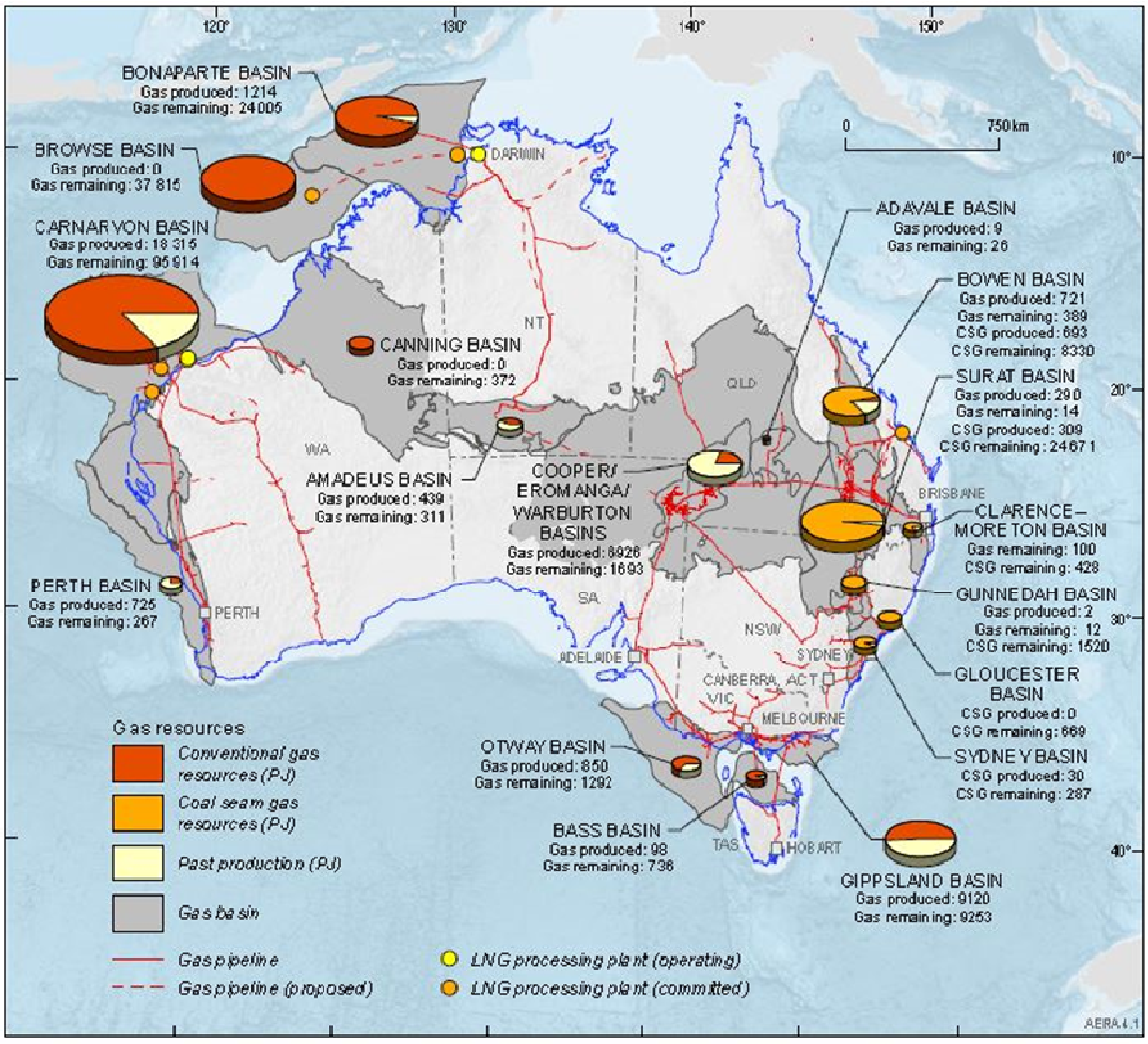


However, the LNG market has undergone fundamental change during the last decade which has had a dramatic impact on investment dynamics. The market has matured and now has a global reach with demand and supply transparency approaching that of other commodities such as oil. Today, there is a relative abundance of LNG supply both in terms of quantum and location. This means that Australia's LNG industry competes with many more countries than it once did.

4.1 Australia has significant undeveloped gas resources

A key reason the investment in Australian LNG processing plants during the last decade was feasible was due to the size of the gas reserves that will feed these plants. In conjunction with Australia's stable fiscal and regulatory environment, the size of its gas reserves have made efficiencies of scale possible that can offset

the fact that it is expensive to build LNG plants in Australia. While it will take a long time for investors to recover costs and begin to see profits, these investments were made with a long term view that many LNG processing plants will operate at full capacity for several decades.



Source: Geoscience Australia and BREE, 2014, *Australian Energy Resource Assessment*, 2nd Ed. Geoscience Australia, Canberra.

Key comments from the 2014 Australian Energy Resource Assessment[2]:

- Australia's gas resources have grown as a result of successful exploration programs and are large enough to support expected domestic and export market growth.
- Australia potentially has significant shale and tight gas resources, but exploration for these commodities within Australia has only recently commenced.
- Significant future investment is required to develop these resources.

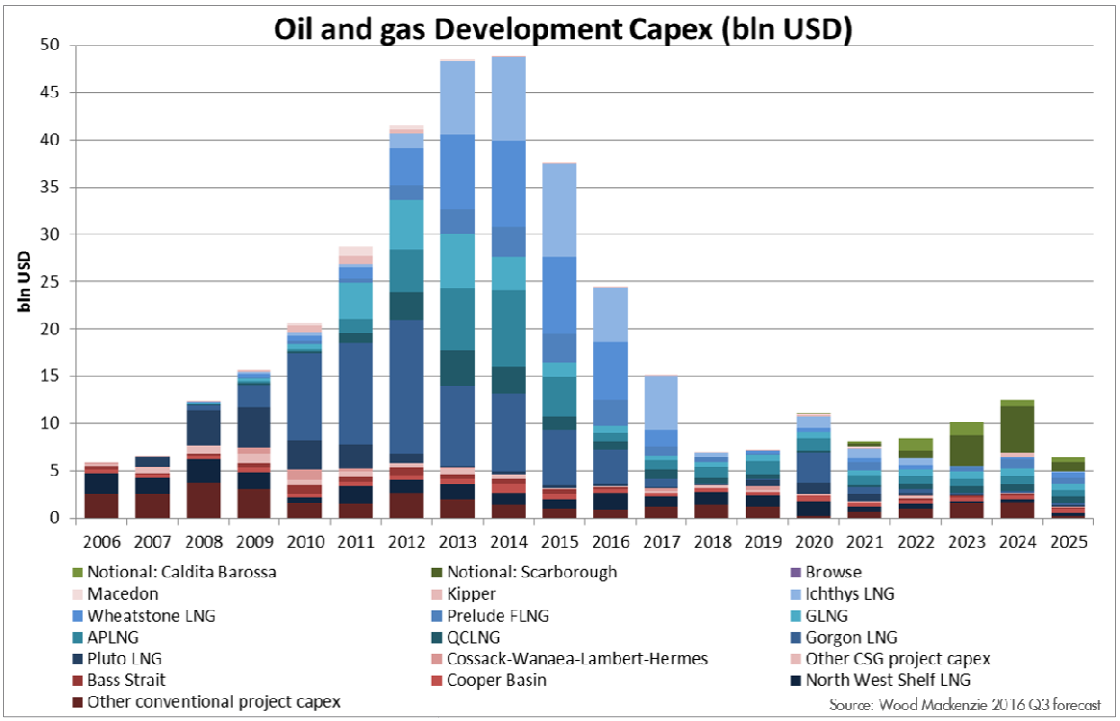
Australia's large gas resources have underwritten the LNG plants recently constructed or under construction. However, only a portion of those resources have been developed and are being used as feed gas for current production operations. The existing LNG projects will require considerable further investment over the coming decades to develop additional gas resources needed to keep the processing plants operating at full capacity.

[2] Geoscience Australia and BREE, 2014, *Australian Energy Resource Assessment,* 2nd Ed. Geoscience Australia, Canberra https://industry.gov.au/Office-of-the-Chief-Economist/Publications/Documents/GA21797.pdf.

It is also possible that a number of new LNG plants may be developed to process gas from large discoveries that are not close to existing infrastructure (e.g. Browse, Scarborough, Sunrise). The table below highlights the breadth of projects that remain uneconomic under current market conditions, the future commerciality of which will be further impacted by changes to Australia's fiscal regime. Australia needs to remain internationally competitive if the investment pipeline is to continue.

Field	***Volume (Tcf)***	***First discovered***
Browse	16	1971
Sunrise	5.13	1974
Scarborough	6.9	1979
Evans Shoal	6.6	1988
Barossa-Caldita	~1.5-2.5	2005-2007
Thebe	1.8	2007

Source: Company websites



Australia has abundant gas resources and under-explored areas that could sustain and extend the life of existing LNG plants, drive further growth in domestic gas and further LNG developments, and provide substantial benefits to the Australian economy and community. However, in order for Australia to compete for continued global demand for gas, the after-tax investor returns from Australian LNG projects must be internationally competitive over the full project life cycles.

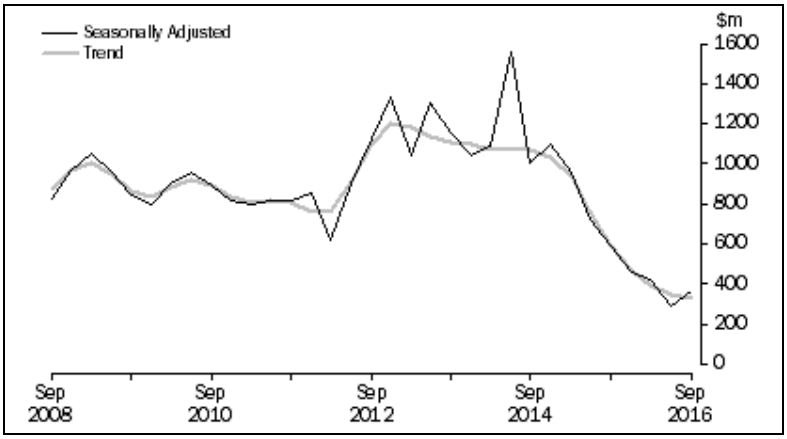
The long life cycle of LNG projects means they are uniquely sensitive to fiscal settings. Recognising this, many other countries provide specific undertakings to investors that fiscal settings will remain constant over the life of the project. If Australia does not maintain its fiscal competitiveness and reputation for fiscal and regulatory stability, it risks missing the opportunity to monetise its substantial gas resources and the prosperity associated with this.

4.2 The importance of further exploration

Exploration is critical to the sustainability and growth of Australia's oil and gas industry. The industry has enjoyed significant success with discovered gas resources increased five-fold over the past 40 years. However, petroleum exploration activity in Australia has dramatically declined in recent years, partly due to falling oil prices and a drive by companies to focus on reducing costs and delivering more efficient production from operating projects.

Wood Mackenzie notes that the "high costs of finding and developing new oil and gas fields that can be commercially developed has created a challenging atmosphere, with explorers increasingly seeing low returns, low value and slow progress".[3] The global trend in recent years, which started before the fall of oil prices, has been both a decline in exploration activity and a move away from frontier and deep-water exploration to onshore and mature shallow-water basins near existing projects.

Petroleum exploration expenditure in Australia 2008-2016, ABS[4]



This may have significant implications for the Australian oil and gas industry because "vast under-explored offshore sedimentary basins on Australia's continental margin are regarded internationally as prospective frontier regions and hold significant promise for future oil and gas resources."[5]

It is widely believed that Australia has significant undiscovered oil and gas resources, including CSG, shale and tight gas resources. However, state moratoriums on unconventional exploration and development will mean the sustainability and growth of Australia's oil and gas industry will be challenged by less access to lower cost supply from onshore resources.

Accordingly, the impact of this petroleum exploration trend on Australia needs to be considered as part of the Australian Government's PRRT review and the broader fiscal reform debate. Exploration is now being focussed on not just the most highly prospective areas, but those with competitive lifecycle costs. That is, prospectivity alone will not drive exploration if the after-tax returns to investors, from exploring through to development, production and rehabilitation, are not forecast to be more compelling than other global exploration opportunities.

[3] Wood Mackenzie, *Global exploration trends*, May 2016, https://www.woodmac.com/reports/oil-and-gas-exploration-global-exploration-trends-38729753.

[4] Australian Bureau of Statistics, *8412.0 - Mineral and Petroleum Exploration, Australia, Sep 2016*, Australian Government, http://www.abs.gov.au/ausstats/abs@.nsf/mf/8412.0.

[5] Geoscience Australia and BREE, 2014, *Australian Energy Resource Assessment,* Forward, 2nd Ed. Geoscience Australia, Canberra https://industry.gov.au/Office-of-the-Chief-Economist/Publications/Documents/GA21797.pdf.

5. Continued investment in Australian projects

The fundamental competitive factor that drives investment in LNG projects is the landed cost of the LNG sourced from that project, or the total cost to deliver the LNG to its customers. Australia faces a key challenge here, because the landed cost for Australian-sourced LNG is higher than many other countries.

5.1 Cost and location challenges associated with Australian projects

Australian LNG projects have been costly to develop. The challenges of developing resources off the North West of Australia, or the large geography over which Queensland's CSG resources have been developed, in combination with construction of LNG processing plants in locations far from Australia's urban centres, has contributed to the complexity and costs of developing these mega projects.

Australian LNG projects have surmounted significant technical challenges that have involved world-firsts:

- QCLNG was the first project in the world to produce LNG sourced from coal seams;
- Prelude will be the first floating LNG project in Australia, deploying revolutionary technology to develop resources in offshore locations remote from onshore infrastructure; and
- The Gorgon LNG plant was built on a Class A nature reserve island 50km off the WA coast, and incorporates the largest carbon dioxide sequestration project in the world.

Whilst these technical achievements are impressive, they come at a cost and have been necessary to overcome disadvantages not faced by Australia's global competitors in LNG.

5.1.1 A competitive comparison – North America

The competitive challenges facing Australian oil and gas resources projects are illustrated by comparison to the developing LNG industry of the United States, which many analysts consider to be Australia's strongest competitor for securing new LNG demand:

- The United States is expected to become the world's third-largest LNG supplier by 2020 with an export capacity of around 60 mtpa from five export terminals[6].
- In hindsight, the shale gas revolution has been unprecedented, production volumes from horizontal wells have been increasing despite a reduction in drilling over the past five years. Industry expectations were surpassed by the resiliency of shale gas and the eventual growth was not captured in models in early stages. With record storage along with ample undrilled acreage, US LNG exporters are taking advantage of low cost supply despite the global LNG price slide.[7]
- The emergence of shale gas available in large quantities in several supply basins across the US has provided an extensive, low-cost gas resource base[8].

The US LNG industry is expanding rapidly due to low cost feed gas, but also due to less and lower costing infrastructure requirements relative to Australia. The US already has a comprehensive domestic gas network in areas close to new shale gas projects. Linking new LNG processing plants with feed gas from shale, largely using existing domestic gas pipelines, is a much less demanding process than what is required by most Australian LNG projects. The US domestic network also has better developed third party pipeline access rights and is a deep, transparent and functioning market.

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[6] See e.g. LNG World News, *Report: Asia becoming largest importer of U.S. LNG* (2017), http://www.lngworldnews.com/report-asia-becoming-largest-importer-of-us-lng/.

[7] Deloitte, *Five years on: The outlook and impact of American LNG exports* (2016), https://www2.deloitte.com/content/dam/Deloitte/us/Documents/energy-resources/us-er-five-years-on-the-outlook-and-impact-of-american-lng-exports.pdf.

[8] Deloitte, *Five years on: The outlook and impact of American LNG exports* (2016), https://www2.deloitte.com/content/dam/Deloitte/us/Documents/energy-resources/us-er-five-years-on-the-outlook-and-impact-of-american-lng-exports.pdf.

Adverse changes made to the Australian taxes applicable to these LNG projects will represent an increase in project costs to investors, relative to LNG projects in competing countries like the US, and will diminish the competitiveness of existing and potential projects. Furthermore, adverse changes to the tax system risks Australia's reputation for stable fiscal and regulatory arrangements. This impact to investor confidence would be particularly harmful if fiscal amendments are made that have the effect of reducing returns to investors on capital that has already been committed.

6. PRRT design features

In this section we have made some observations on some of the design features of PRRT, as raised in the 20th December 2016 Issues Note, and our practical experience of applying these elements in compliance with the PRRTAA. We note that the PRRT was designed to work as an integrated package of measures.

The appropriateness of particular features is determined by the nature of the oil and gas industry and the overall intention of the PRRT as expressed by the federal governments, at the relevant times, and the language of the legislative material.

The current design features of the PRRT ensure an equitable and practical balance between ensuring a fair return to Australia for its finite oil and gas resources, supporting the continuation of existing projects and not discouraging much-needed continued investment.

6.1 Losses and the structure of uplift rates under PRRT

A fundamental design feature of the PRRT regime is the recognition of investor risk in the determination of a tax liability. The augmentation rates contained in the current law provide a mechanism for addressing this risk and are a key element to determine the economic rent generated by a project. This is critical to the object and intention of the PRRT.

Taxpayers do not benefit from an immediate tax offset for expenditure incurred under the PRRT and must carry-forward undeducted expenditure in a year to offset future revenues. The undeducted expenditure is augmented at different rates, depending on the nature and timing of that expenditure.

Expenditure incurred more than 5 years prior to the issue of a production licence is augmented at a GDP-based rate. More recent expenditure is augmented at higher rates - the Commonwealth Long Term Bond Rate (LTBR) plus an uplift of 15% for exploration expenditure and LTBR+5% for general project expenditure.

It follows that the augmentation rates are designed to keep the value of expenditure constant in real terms as it is carried forward to deduct in future years and also to recognise the inherent variation in risk to investors of the different stages of the investment cycle. Further, without the uplift provided by augmentation, investors would pay tax before economic rent has been earned from a project. Augmentation also recognises the fact that finance costs are not deductible for PRRT.

Some commentators have suggested the uplifts for investment risk of 15% and 5% for exploration and other upstream project activities respectively are too generous. The majority of PRRT project expenditure is development and construction expenditure, which receives annual augmentation of LTBR+5% (i.e. currently around 7.6%). In our view, the augmentation rates are, on an overall project lifecycle basis, currently below what would be considered a reasonable benchmark rate of return for the oil and gas industry given its high risk nature.

In order to assess the reasonableness of the augmentation rates, it is necessary to consider the average or expected after-tax returns on investment for the oil and gas industry and other capital intensive industries. For the oil and gas industry, most industry analysts and consultants apply an after-tax IRR of around 15% to determine whether a project is economic. This threshold recognises the weighted average cost of capital for large oil and gas companies is typically around 10-12%. Investors will generally not make investment

decisions without a high degree of confidence that the after-tax returns will exceed the cost of capital over the life of the investment.

Looking outside of the industry, AMP Capital is currently forecasting indicative after-tax yields for infrastructure investments of around 5.5% over the next 5 years[9]. This average is based on estimates of around 3% for airports to 9% for social infrastructure. The indicative after-tax IRRs required for these projects to support those yields are between 7% and 15%.

Again, considering the fact that the majority of PRRT project expenditure is augmented at LTBR+5% (i.e. currently around 7.6%), the profit threshold set by the current augmentation rates is reasonable relative to other capital intensive sectors, including Australian infrastructure, which are lower risk investments.

6.2 Transferability of PRRT exploration expenditure

Exploration expenditure incurred after 30th June 1990 is transferable between projects where all conditions for transferability are satisfied. Broadly, this requires the transferring project and the recipient PRRT project with excess profits to have been held by the same taxpayer group continuously since the exploration expenditure was incurred. This is an appropriate design feature not only because of the integrity measures concerning common ownership and timing of expenditure transfer, but because it also recognises the high costs and risks associated with exploration.

If exploration expenditure was not transferrable, the PRRT would act as an incentive to explore only in areas where a discovery is likely to supply existing PRRT projects. As such, after-tax exploration costs in established areas would be lower than for prospective frontier areas. This outcome would be at odds with the objective of removing impediments to petroleum exploration and encouraging exploration in under-explored or frontier areas, particularly at a time of historically low levels of exploration activity in Australia.

6.3 PRRT starting base arrangements

The starting base arrangements for the 2012 transition of the NWS and onshore oil and gas projects into the PRRT regime are a key transitional design feature of the PRRT. These arrangements seek to address the retrospective application of the tax to projects whose investment decisions were made prior to the announcement of the extension of the PRRT regime and remain subject to other resource taxes such as production excise and royalties. The starting base provides investors in the NWS project onshore projects with a recognition for past costs and the value of existing assets. Without such recognition investors would have been disadvantaged, leading to the premature payment of PRRT before earning economic rent from the project. This measure ensured Australia's competitiveness is the global oil and gas market and investor confidence was not eroded through fiscal instability.

A further transitional measure to provide a credit against PRRT for existing resource taxes ensures transitioning projects are not subject to double taxation. This recognises that resource taxes such as Commonwealth condensate/oil excise and royalties imposed by the Commonwealth, State and Territory governments are the primary taxing mechanism for the NWS project and onshore projects.

6.4 Application of PRRT to gas projects

There are two key questions that appear to have been raised with respect to the application of the PRRT to gas projects:

1. Are the PRRT outcomes for gas projects consistent with those for oil projects?

[9] Dr. Shane Oliver, *Infrastructure investing in a world of low interest rates* (2016), AMP Capital http://www.ampcapital.com.au/article-detail?alias=%2Folivers-insights%2Faugust-2016%2Finfrastructure-investing-low-interest-rates.

2. Do the fundamental economic differences between oil and gas mean that changes to Australia's resource tax framework are necessary to ensure the community receives a fair return for both resources?

On responding to these questions it is important to recognize that the PRRT was designed to apply to all oil and gas production. This is reflected in the categories of MPC included in the PRRTAA, which specifically includes sales gas that can feed domestic gas demand and LNG production.

6.4.1 Consistency of PRRT outcomes for oil and gas projects

Expenditure relating to LNG projects needs to be apportioned between the upstream (deductible for PRRT) and downstream (not deductible) operations under the general apportionment principles of PRRT and its GTL regulations. This ensures that the PRRT outcomes for LNG projects are consistent with those for oil projects, as only expenditure with a direct or close connection with producing and storing the MPC is deductible for PRRT purposes. That is, the PRRT is applied to the inherent value of the oil and gas commodities prior to the occurrence of any value-adding processes.

Any concerns that the apportionment principles of the PRRT do not produce consistent outcomes for oil and gas projects are misplaced. Apportionment is a fundamental concept of most tax legislation, as well as accounting standards. The PRRT requires taxpayers to apportion expenditure to the upstream activities of a project on a reasonable basis. In this regard the ATO has robust processes, including review and audit, to ensure that taxpayers comply with the PRRTAA.

Regulations accompanying the PRRTAA were introduced in 2005 to provide a methodology for determining the transfer price for sales gas in LNG projects, which includes mechanisms to apportion expenditure that relates to the production and storage of (sales gas versus the value-added liquids (e.g. LNG) produced from the gas. This is discussed further below under PRRT gas transfer pricing measures.

6.4.2 The application of PRRT to FLNG projects

The FLNG concept was developed for the purpose of accessing 'stranded gas'. Stranded gas is a term for gas fields that are in offshore locations where remoteness and/or subsea difficulties mean it would not be economically or technically feasible to produce LNG using existing or new onshore LNG processing plants. If FLNG was not utilised, such gas reserves would either not be developed in the foreseeable future, or would be developed in ways that produce lower returns for both investors and governments.

We appreciate that FLNG is a new concept and there may be some perceived uncertainty in relation to the application of PRRT to these projects. The participants of the Shell operated Prelude FLNG project will not be required to lodge a PRRT return for their interests in the project until an MPC is first produced. In our view, the PRRT outcomes for an FLNG project will not materially differ to projects with offshore gas fields and onshore LNG plants.

There are no provisions under PRRT legislation that uniquely apply to FLNG projects and, in our view, none are necessary. The FLNG facility is essentially an LNG processing plant built on a very large floating structure (currently the largest in the world). The main difference between FLNG and conventional onshore LNG plants that is relevant for PRRT purposes is the floating infrastructure (e.g. the hull, turret and moorings). Further, FLNG projects do not require a lot of the land-specific infrastructure, including jetties and the works associated with constructing facilities on land.

Expenditure relating to both FLNG and onshore LNG processing plants needs to be apportioned between the upstream (deductible for PRRT) and downstream (not deductible) operations. The capital expenditure relating to differences between FLNG and onshore LNG processing plants is much less than the expenditure on infrastructure and equipment that is common to both, including processing and storage components. Accordingly, in our view, the PRRT outcomes for FLNG projects will be materially consistent with conventional LNG projects.

Oil fields with similar location challenges lead to the development of FPSO vessels. Like FLNG, FPSO vessels essentially house equipment and infrastructure that would normally be located onshore and/or on an offshore oil platform. Most, if not all, expenditure directly related to an FPSO would be deductible for PRRT purposes. Accordingly, the main difference for PRRT purposes between an FPSO oil project and an FLNG project is that the conversion of processed natural gas to LNG is a value-adding process which is beyond the scope of PRRT. This difference also arises in conventional LNG projects.

6.5 PRRT gas transfer pricing measures

The PRRT gas transfer pricing regulations were developed to clarify PRRT outcomes for taxpayers with interests in GTL projects. This is because the taxable commodity for PRRT is the sales gas produced as feedstock for conversion to a liquid (e.g. LNG), rather than the LNG itself. Accordingly, it is necessary to determine the value of the sales gas at the point it is produced in the LNG plant before the occurrence of value-adding process of converting the gas to LNG. The PRRT Regulations set out the approaches taxpayers can adopt in order to comply with the PRRTA. In the absence of an Advance Pricing Arrangement or a comparable uncontrolled price observed in the market, the RPM is provided under the PRRT Regulations to price the gas.

The current RPM was designed through significant collaboration between government and industry to provide an equitable sharing of the risk between the upstream and downstream stages of a GTL project. The RPM applied by taxpayers to their projects and the resulting gas transfer price outcome is closely administered by the ATO.