TAXATION AND PRICING OF NATURAL GAS: THE DUTCH TRANSITION TO A GAS MARKET HUB AND LESSONS FOR AUSTRALIA'S INTEGRATED GAS PROJECTS

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The Australian government receives poor revenue returns from the Petroleum Resource Rent Tax ('PRRT'), a tax regime that applies to integrated offshore, gas projects. By contrast the Netherlands has captured significant tax revenues from gas. We ask whether Australian government PRRT revenue would increase from an alternative method of gas pricing (known as the gas transfer price) by modelling four large gas projects. The Dutch case explains their gas market evolution and how high revenues have been maintained. We find that Australia's current PRRT regulated pricing method for integrated gas projects is problematic and change is needed. The Dutch case study contextualises the discussion of an alternative gas transfer pricing method for offshore gas projects in Australia. The energy justice framework is used for analysis. This article contributes to the current government review of the PRRT regulations on the gas transfer pricing method.

I INTRODUCTION

Traditionally in the United States ('US') and Europe, the operation of a physical gas hub preceded the evolution of reliable market-indexed pricing.[1] A gas market hub is defined as a 'contractual point where buyers and sellers

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1 United States Energy Information Administration, 'Introduction' in *Perspectives on the Development of LNG Market Hubs in the Asia Pacific Region* (Report, March 2017) 1 ('*2017 Development of LNG Market Hubs in Asia Report*') 1.

execute transactions for gas. Hubs can be notional or physical, transregional (one or more transmission system operators ('TSOs')) or within-country (one TSO)'.[2] Hubs normally have a hub services agreement (operator) and a trading contract (trader). Examples of notional hubs that reflect trade over a defined network are the National Balancing Point ('NBP') in the United Kingdom ('UK') and the Title Transfer Facility ('TTF') in the Netherlands. These hubs reflect how physical transport within the network is separated from the commercial trade. Physical hubs include the Henry Hub in the US and the Zeebrugge Terminal in Belgium. A physical hub, also called a market centre, is 'where multiple pipelines or electric transmission lines interconnect'.[3]

In contrast to the well-established gas pipeline networks, such as within the US and the intra- and inter-pipelines in Europe, a general distinguishing feature of the Asia-Pacific gas trade is the vast distances between supplier and customer.[4] Projects are typically integrated, whereby the gas extracted needs to be liquefied for transport by tankers to overseas customers. For Australia, the other differentiating feature of many integrated gas projects is the regulatory requirement to determine a gas transfer price ('GTP'), which will be explained later.

The main liquefied natural gas ('LNG') exporters to Asia-Pacific (Australia, Malaysia, the US and Papua New Guinea) lack inter-country pipelines.[5] For gas sourced in Australia there is no notional gas market hub for efficient LNG export pricing. Suppliers of Australian source LNG primarily rely on confidential, long-term gas pricing contracts for their customers located in Japan, South Korea, China and Taiwan.[6] For example, Chevron's LNG long-term contracts (and spot price contracts) ensure a reasonable return on their gas project investments, including coverage of taxes.[7] For import customers in Asia, long-term contracts guarantee security of supply.

A The Investigation

This investigation arises from the *Petroleum Resource Rent Tax Review Final Report 2017* ('*Callaghan Report*')[8] to address, inter alia, the poor revenues

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2 PriceWaterhouseCoopers, *LNG: A Glossary of Terms* (Petroleum Economist, 3rd ed, 2006) 41.

3 Ibid 53.

4 The US is active in the Asia-Pacific gas trade, and exports to China and Korea using the Panama Canal route: see, eg, Osamu Tsukimori, 'Panama Canal to Carry 30 Million Tonnes of LNG by 2020 as Global Demand Grows,' *Reuters* (online, 20 April 2018) <https://www.reuters.com/article/us-japan-panamacanal/panama-canal-to-carry-30-million-tonnes-of-lng-by-2020-as-global-demand-grows-idUSKBN1HR0VB>.

5 Note there is the Malaysia to Thailand link, the Trans Thai-Malaysia gas project: 'Overview', *Trans Thai-Malaysia (Thailand) Limited* (Web Page) <http://www.ttm-jda.com/content/overview/?lang=eng>.

6 Younkyoo Kim, 'Obstacles to the Creation of Gas Trading Hubs and a Price Index in Northeast Asia' (2019) 22(2) *Geosystem Engineering* 59, 64.

7 For example, Milne mentions the economic importance of long-term contracts and spot pricing: Peter Milne, 'Chevron LNG Projects Gorgon and Wheatstone Earning $32 Million a Day', *The West Australian*, (online, 5 February 2018) <https://thewest.com.au/business/oil-gas/chevron-lng-projects-gorgon-and-wheatstone-earning-32-million-a-day-ng-b88734044z>.

8 *Petroleum Resource Rent Tax Review* (Final Report, 13 April 2017) ('*Callaghan Report*'). See page 2 for the terms of reference, which includes, drawing 'on international experience, the review will make

from petroleum rent taxation. The report made a series of recommendations that included calling for a review of feedstock gas pricing, known as the GTP, as required for Australian integrated gas projects that do not have a gas hub or observable market price. The momentum to fix low Petroleum Resource Rent Tax ('PRRT') revenues continued after the early 2018 report from the Australian Parliamentary Budget Office that stated although 'the tax base for the PRRT is expanding, there is a significant likelihood that this will not translate into higher PRRT revenue'.[9] The Senate Economics References Committee May 2018 Report on corporate tax avoidance also identified the need to review regulations on the GTP method.[10]

Given the government has accepted many *Callaghan Report* recommendations to remedy PRRT design flaws,[11] this investigation covers one of the last remaining design issues: the pricing of gas at the point where it first becomes a Marketable Petroleum Commodity ('MPC'), as defined in section 2E(1) of the *Petroleum Resource Rent Tax Assessment Act 1987* (Cth) ('*PRRTA Act*'), in cases where there is no arms-length or market price. An MPC forms part of assessable petroleum receipts,[12] one of the elements to determine 'taxable profit' at the PRRT taxing point.[13] Figure 1 shows the location of the PRRT taxing point. The *PRRTA Act* provides for tax on the 'taxable profit' (the common term is 'economic rent') from petroleum projects. Taxpayers with offshore petroleum projects can be liable to pay both income tax on normal profits, ie, 'taxable income', as well as the PRRT tax, which is an income tax deduction.

In Australia, the largest gas projects typically do not have an arms-length price because gas extractors (upstream) and the gas liquefiers (downstream) form an integrated project under a common operator entity. If the gas extracted is used as feedstock for processing into liquefied natural gas and subject to a non-arms-length sale between upstream and downstream, then assessable petroleum receipts are determined by applying section 20 of the *Petroleum Resource Rent*

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recommendations to the Government on future tax, excise and royalty arrangements having regard to revenue adequacy, efficiency, equity, complexity, regulatory costs and the impact on the industry generally'.

9 Parliamentary Budget Office (Cth), *Trends Affecting the Sustainablity of Commonwealth Taxes* (Report No 02/2018, 2018) 29. Others to call for a Gas Transfer Price ('GTP') review include Diane Kraal, 'Review of Australia's Petroleum Resource Rent Tax: Implications from a Case Study of the Gorgon Gas Project' (2017) 45(2) *Federal Law Review* 315 ('Review of Australia's PRRT'); Marieke D'Cruz and Richard Holden, McKell Institute, *Harnessing the Boom: How Australia Can Better Capture the Benefits of the Natural Gas Boom* (Report, March 2017).

10 Senate Economics References Committee, Parliament of Australia, *Corporate Tax Avoidance Part 3: Much Heat, Little Light So Far* (Report, May 2018) ('*Corporate Tax Avoidance Report*'), ix [3.68].

11 Treasury (Cth), 'Government Response to the Petroleum Resource Rent Tax Review' (Media Release, 2 November 2018) ('Government Response'). Accepted recommendations are now legislated; they include lower uplift rates and removal of onshore petroleum projects from the PRRT regime.

12 *Petroleum Resource Rent Tax Assessment Act 1987* (Cth) s 23(1)(a) ('*PRRTA Act*').

13 The taxing point is where assessable receipts are brought to account, and up to which eligible project expenditures incurred (deductible expenditure) are deducted to determine the PRRT 'taxable profit', defined in s 22 of the *PRRTA Act*.

Tax Assessment Regulation 2015 (Cth) ('*PRRTA Regulation*'). It directs a taxpayer to use the prescribed GTP method.[14] Figure 1 depicts the upstream and downstream components of an integrated gas project.

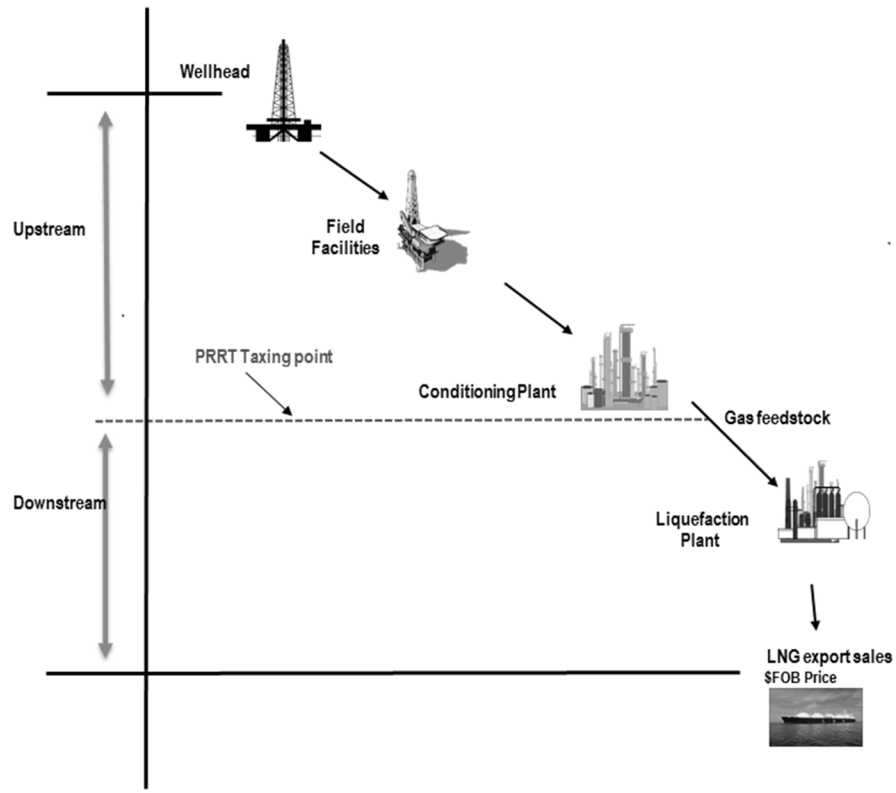

Figure 1: Integrated Gas Project – Gas Is Produced Upstream and Liquefied Downstream

It is noted that LNG is the result of gas (feedstock) processing in the liquefaction plant, and the modified (liquid) product is excluded from assessable petroleum receipts, as per section 24(1)(c) of the *PRRTA Act*.

Price is an element in the calculation of PRRT taxable profit. Taxpayers are required to calculate the GTP in non-arms-length situations. The higher the GTP, the more revenue to the government. At the PRRT taxing point, the regulation GTP is derived and multiplied by the gas feedstock volumes, from which project capital and operating costs are deducted to determine the project's taxable profit. A 40% tax rate is applied to a petroleum project's PRRT taxable profit. The

14 *Petroleum Resource Rent Tax Assessment Regulation 2015* (Cth) ('*PRRTA Regulation*'). Section 20 firstly requires an advanced pricing arrangement or usage of a comparable uncontrolled price, but if neither exist, then the residual pricing method ('RPM') must be used to determine the 'gas transfer price' of sales or feedstock gas. See Kraal, 'Review of Australia's PRRT' (n 9) 341.

problem is whether the regulation GTP method is the most 'appropriate' way of determining the price of the gas feedstock in an integrated gas project.[15]

Our research hypothesis is that the Australian government's PRRT revenue would increase from an alternative method of calculating the GTP, compared to the current method prescribed at section 24 in the *PRRTA Regulation*.

Using the Dutch experience as a case study, we will first prepare a narrative on the evolution of its gas market and how the Dutch state has maintained high revenues from its domestic gas production.

The method of fiscal system modelling is used for the hypothesis, with data input from four of the largest integrated gas projects off the north-west coast of Australia. The Dutch case study is drawn on to contextualise the discussion of Australian findings on the GTP methods. The energy justice framework is used to analyse the findings.

Energy justice is a concept used in energy law and policy, with a provenance of at least ten years in law and social science literature.[16] Thus, although economic fundamentals[17] are arguably critical to Australia's gas policy, there are other factors, such as political and environmental issues, that pull policy in different directions. For instance, November 2018 saw the Government's final response to the *Callaghan Report*. Likely due to political expediency, the Government, inter alia, accepts the need to review the GTP regulations.[18]

This article's research findings draw on the lessons from the Netherlands' experience with gas pricing. The GTP modelling findings indicate that for four of the largest Australian gas projects over the period 2012–30 Australian government revenues under the proposed alternative method would be USD15.5 billion, compared to USD5.5 billion under the current *PRRT Regulation* method. The 2019–20 budget for all gas projects in Australia shows poor PRRT revenues of only AUD1.4 billion per annum to 2023.[19]

This research builds on previous work that concerned modelling selected changes to the design of Australia's *PRRTA Act* and applied them to the Chevron-operated Gorgon LNG project, an integrated natural gas operation off

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15 The word 'appropriate' is from the terms of reference: *Callaghan Report* (n 8) 2. The terms of reference include, '[t]he review will have regard to the need to provide an appropriate return to the community on Australia's finite oil and gas resources while supporting the development of those resources, including industry exploration, investment and growth'.

16 See, eg, Benjamin K Sovacool et al, 'Energy Decisions Reframed as Justice and Ethical Concerns' (2016) 1(5) *Nature Energy* 1; Raphael J Heffron and Darren McCauley, 'The Concept of Energy Justice across the Disciplines' (2017) 105 *Energy Policy* 658; Darren McCauley and Raphael Heffron, 'Just Transition: Integrating Climate, Energy and Environmental Justice' (2018) 119 *Energy Policy* 1.

17 'Economic fundamentals refer to the cost of developing and delivering domestic or imported gas to end-users': Jonathan Stern, 'International Gas Pricing in Europe and Asia: A Crisis of Fundamentals' (2014) 64 *Energy Policy* 43, 43.

18 'Government Response' (n 11); *Callaghan Report* (n 8).

19 See Commonwealth, *Budget 2019–20: Budget Strategy and Outlook* (Budget Paper No 1, 2 April 2019), 4–17. Since the effective date of the *PRRTA Act* to 2018, there has been approximately AUD35 billion in tax receipts to the government: Kraal, 'Review of Australia's PRRT' (n 9) 344. Note the proven gas reserves in 2008 for the Netherlands were 1.2 Tcm and Australia 2.7 Tcm: *BP Statistical Review of World Energy* (Report, 68th ed, 2019) 30.

north-west Australia.[20] For this current research, three additional integrated gas projects in Australia are modelled, but with the focus solely on the gas transfer pricing method prescribed by *PRRTA Regulation*. Together the four projects provide further empirical evidence to support the argument for a change to the regulations. This empirical research is thus limited to Australia's dominant offshore petroleum projects (in terms of gas production per annum). The offshore gas is extracted from basins in waters under Australian federal jurisdiction.

The article proceeds as follows: Part II discusses the relevant literature; Part III presents the research methodology; Part IV covers the Dutch case study; Part V presents the modelling and findings for the selected gas projects in Australia; and Parts VI and VII contain the analysis, recommendation and conclusions.

II LITERATURE

Each Australian state and territory has legislation that provides for the reservation of onshore petroleum resources to the Crown on trust for its citizens. These laws modify the doctrine that the 'landowner in possession of the surface of the land owned any minerals, including any petroleum found in the subsurface of the land'.[21] As for offshore minerals, under the 1979 Offshore Constitutional Settlement, the Commonwealth's jurisdiction for petroleum (oil and gas) resources is seaward of the three nautical mile boundary. For coastal water projects that lie within the low tide mark and the three nautical mile boundary, both the state and the Commonwealth hold taxing rights.[22] The various state legislations typically levy a royalty for onshore resource extraction based on the production value.

Australia's resource rent tax legislation took effect in 1988 and applied to petroleum production from future offshore oil fields in Commonwealth waters, with some exceptions.[23] The PRRT generally replaced federal production royalties and is applied to above-normal profits (economic rent) and levied in

20 Kraal, 'Review of Australia's PRRT' (n 9) 316.

21 Penelope Crossley, 'The Australian LNG Industry: Legal and Commercial Challenges' in Slawomir Raszewski (ed), *The International Political Economy of Oil and Gas* (Palgrave Macmillan, 2018) 139, 141, citing *Perth v Halle* (1911) 13 CLR 393, 399 (Griffith CJ).

22 The 1979 settlement was published by the Commonwealth Attorney-General's Department. See generally Legislative Assembly Economics and Industry Standing Committee, Parliament of Western Australia, *The Economic Impact of Floating LNG on Western Australia* (Report No 2, May 2014) vol 1, 29–30; Diane Kraal, 'The Petroleum Resource Rent Tax: Overview of Primary Documents and Literature Leading to the 1987 Legislation' (Working Paper No 9/2016, Tax and Transfer Policy Institute, Australian National University, October 2016) 22 ('Overview of Primary Documents'). See also Richard Cullen, 'The Encounter between Natural Resources and Federalism in Canada and Australia' (1990) 24(2) *University of British Columbia Law Review* 275, 296–7.

23 See Explanatory Memorandum, Petroleum Resource Rent Tax Assessment Bill 1987 (Cth). The petroleum field exceptions at the time were Victoria's Bass Strait and the North West Shelf Project off the West Australian coast. Onshore gas projects were added in 2012: see Kraal, 'Overview of Primary Documents' (n 22) 12, 15.

addition to income tax.[24] The PRRT was designed for highly profitable oil projects, not integrated gas projects that have lower profitability,[25] as can be evidenced by the original exclusion of the North West Shelf gas project in 1987 and the recent exclusion (from mid-2019) of the low-profit east coast onshore gas projects.[26]

The Asia-Pacific region still relies on confidential long-term contracts by suppliers and import customers, although these are supplemented by spot trading. The dominance of non-transparent pricing has prompted the emergence of literature that canvasses the establishment of a market hub for gas pricing in the Asia-Pacific.[27] However, the discourse on future developments for the Asia-Pacific LNG export market, such as a gas hub, is dominated by importers in East Asia. For example, Shi has called for the development in East Asia of LNG trading hubs by importer countries.[28] He argues hubs will allow easier cost-saving changes to contracts in the future, but they would require cooperation between importers and gas exporters.[29] He claims the natural gas market in East Asia will remain fragmented without a functioning benchmark price that a hub could provide along with well-developed physical spot trading.

Recently Japan, China, and Singapore launched competing LNG pricing indexes. These are part of long-term strategies that aim to both increase the transparency and efficiency of gas pricing, and to include various trades in financial instruments. Such market-index strategies must include 'a regulatory environment that assures equal third-party access to natural gas infrastructure (pipelines, regasification facilities, storage, etc)'.[30] The US Energy Information Administration ('EIA') sees a better chance for success in Japan over the long-term because China's gas prices are over-regulated and Singapore has limited storage infrastructure as a hub.[31] Shi, Li and Reshetova agree with the EIA that a

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24 Kraal, 'Overview of Primary Documents' (n 22). Income tax assessment is covered by the *Income Tax Assessment Act 1936* (Cth) and the *Income Tax Assessment Act 1997* (Cth). Differences between the PRRT and income tax include: income tax allows a deduction only for depreciation on capital, while the PRRT expenses capital outlays; and income tax allows a deduction for debt interest but debt interest is not deductible for the PRRT.

25 Kraal, 'Review of Australia's PRRT' (n 9) 325.

26 'Government Response' (n 11).

27 Vlado Vivoda, 'Natural Gas in Asia: Trade, Markets and Regional Institutions' (2014) 74 *Energy Policy* 80; Jeff D Makholm and Laura TW Olive, 'A Petroleum Tanker of a Different Color: Obstacles to an LNG-Based Global Gas Spot Market' (Working Paper, National Economic Research Associates, 2 May 2016); Hamed Nikhalat-Jahromi et al, 'Global LNG Trade: A Comprehensive Up To Date Analysis' (2017) 19(1) *Maritime Economics and Logistics* 160; Younkyoo Kim, 'Asian LNG Market Changes under Low Oil Prices: Prospects for Trading Hubs and a New Price Index' (2017) 20(3) *Geosystem Engineering* 129; Jinsok Sung, 'The Impact of US LNG Exports and the Prospects For Price-Competitiveness in the East Asian Market' (2017) 10(4) *Journal of World Energy Law and Business* 316.

28 Xunpeng Shi, 'Development of Europe's Gas Hubs: Implications for East Asia' (2016) 3(4) *Natural Gas Industry B* 357, 357 ('Development of Europe's Gas Hubs').

29 Xunpeng Shi, 'Gas and LNG Pricing and Trading Hub in East Asia: An Introduction' (2016) 3(4) *Natural Gas Industry B* 352, 352 ('Gas and LNG Pricing').

30 *2017 Development of LNG Market Hubs in Asia Report* (n 1) 2.

31 Ibid 2, 5, 47.

major constraint to the establishment of a hub is the absence of an intra-regional pipeline connection in East Asia.[32]

In a subsequent paper Shi and Variam model a hub with cost minimisation as the aim. Their work illustrates that both benchmark changes in price and flexible contracts will create benefits for East Asia importers, however the impacts are negative for exporter countries, such as Australia.[33] More recently Shi and Variam argue that because of the gas price link to an oil-indexed price,[34] economic and market fundamentals for gas in East Asia differ.[35] Additionally, regional and industry-specific factors require distinctive economics to assess policy options in gas pricing for East Asia.

Japan is the world's largest consumer of LNG, and Australia is its key supplier.[36] Hashimoto and Kleit see Japan's high gas import prices and transactional costs being driven by the lack of competition in the Asia-Pacific. They suggest the solution is a consortium of buyers to create a futures market trading platform for LNG.[37]

Farrell and Sandilya investigate the competition between Singapore, Japan and China for an Asia-Pacific LNG hub.[38] They assess these three potential locations by considering infrastructure, markets and regulation. Vivoda is another researcher who has called for cooperation among Asia-Pacific LNG importers,[39] referencing the success of the use of multiple suppliers in the US.

The literature on market-indexed gas pricing reflects economics as dominant in the discourse on the need for efficient gas pricing and transparency. For instance, Shi,[40] in a journal sponsored by PetroChina,[41] simply looks at the economic benefits to East Asia customers. Further, Shi and Variam,[42] Hashimoto and Kleit,[43] and Farrell and Sandilya[44] provide no consideration of physical or

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32 Xunpeng Shi, Yanfei Li and Elena Reshetova, 'Bottom-Up Design of a Gas Futures Market in East Asia: Lessons from the Dojima Rice Exchange' (2016) 3(4) *Natural Gas Industry B* 377, 377.

33 Xunpeng Shi and Hari Malamakkavu Padinjare Variam, 'Gas and LNG Trading Hubs, Hub Indexation and Destination Flexibility in East Asia' (2016) 96 *Energy Policy* 587, 587 ('Gas and LNG Trading Hubs').

34 In Asia-Pacific the gas price are often linked to the Japanese customs-cleared crude oil price or JCC (also known as the Japanese Crude-Oil Cocktail). The JCC represents 'the average CIF price of all imported crude oil and raw oil in a specified trading period': PriceWaterhouseCoopers (n 2) 45.

35 Xunpeng Shi and Hari MP Variam, 'East Asia's Gas-Market Failure and Distinctive Economics: A Case Study of Low Oil Prices' (2017) 195 *Applied Energy* 800, 801 ('East Asia's Gas-Market Failure'). 'Market fundamentals refer to the price of gas, compared with the price of market substitutes', such as solar and wind: Stern (n 18) 43.

36 See 'Japan: Liquefied Natural Gas (LNG)', *Export.gov* (Commercial Guide, 9 June 2019) <https://www.export.gov/article?id=Japan-Liquefied-Natural-Gas-LNG>. For data, see *2017 Development of LNG Market Hubs in Asia Report* (n 1).

37 Satoru Hashimoto and Andrew N Kleit, 'A Natural Gas Trading Platform for Japan' (Study, April 2017) 1, 18–21.

38 Bradley Farrell and Ajit Sandilya, 'The Gas Hub in Asia' (2017) 57(2) *The APPEA Journal* 444.

39 Vivoda (n 28) 80.

40 Shi, 'Development of Europe's Gas Hubs' (n 28); Shi, 'Gas and LNG Pricing' (n 29).

41 See 'Natural Gas Industry B Editorial Board', *KeAi: Chinese Roots Global Impact* (Web Page) <http://www.keaipublishing.com/en/journals/natural-gas-industry-b/editorial-board/>. PetroChina Company Limited is China's largest oil and gas producer and distributor.

42 Shi and Variam, 'Gas and LNG Trading Hubs' (n 33).

43 Hashimoto and Kleit (n 37).

notional hub benefits to exporters of gas, or indeed, the communities in these supplier countries.

The literature reviewed above is dominated by calls from East Asian customers for greater transparency in the setting of gas prices as the means to improve the Asia-Pacific LNG gas market. In the general call for transparency and efficiency in gas pricing, the literature lacks considerations from the perspective of the region's exporter countries supplying the resource.

Given the unbalanced nature of the literature in favour of the importers' perspectives, the Australian government should perhaps proceed cautiously to a gas market hub because of basic revenue considerations from its taxation and pricing of gas. This article thus takes a conservative, stepped approach in regard to transparency, simplicity and equity in gas pricing, rather than mounting complex arguments about Australia's preferred position on gas market hubs. The article focuses on the PRRT's gas transfer pricing method. In other words, it is better to fix a host country's local situation before venturing further afield.

While there are Organisation for Economic Co-operation and Development ('OECD') guidelines on transfer pricing and general theories on transfer pricing for petroleum, they do not address the problem of whether Australia's GTP method is appropriate.[45]

III METHODOLOGY

The research hypothesis is that Australian government revenue from the PRRT would increase from the alternative 'netback method' of calculating the GTP compared to the current 'residual pricing method' ('RPM'), prescribed at section 20(5) of the *PRRTA Regulation.* A case study on the Netherlands' experience of gas market evolution is presented to explain how the Dutch State maintained high revenues from its domestic production. Data is gathered about the Netherlands' political decisiveness in establishing gas reforms and a market hub. The method of narrative is used to piece together insights about the Dutch transition to a gas market hub.

To test the hypothesis about GTP methods, fiscal system modelling is used. It is an appropriate way of gathering revenue and cost information to iteratively question the current PRRT regulations that prescribe the gas transfer pricing method. We further draw on the Dutch case study to contextualise the discussion of the modelling of PRRT GTP methods.

Four integrated gas projects in Australia are selected: Inpex's Ichthys LNG, Woodside Petroleum's Pluto LNG, and Chevron's Wheatstone LNG and Gorgon

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44 Farrell and Sandilya (n 38).

45 Organisation for Economic Co-operation and Development, *Transfer Pricing Guidelines for Multinational Enterprises and Tax Administrations* (Report, July 2017) ('*Transfer Pricing Guidelines*'); Graham Kellas, 'Natural Gas: Experience and Issues' in Philip Daniel, Michael Keen and Charles McPherson (eds), *The Taxation of Petroleum and Minerals: Principles, Problems and Practice* (Routledge, 2010) 163.

LNG projects. Using economic data from these projects, fiscal scenarios are analysed with the Fiscal Analysis of Resource Industries ('FARI') model from the International Monetary Fund ('IMF'). The FARI model is Excel-based and primarily used for revenue forecasting and fiscal regime design.

A Some Definitions

The netback method calculates for the maximum price that a (downstream) gas to liquids processor would pay for feedstock gas and receive a return on capital. The 'cost-plus method' provides for the minimum price an (upstream) gas producer would accept and earn as return on capital.

In plain language, the cost-plus method starts at the upstream wellhead point (where gas is extracted) and calculates the GTP based on proportional capital and operating costs added together to the taxing point before dividing the total by gas volume (where gas feedstock is held prior to liquefaction). *PRRTA Regulation* section 32 excludes the value of exploration costs, and makes no mention of the value of gas reserves (which the authors note undervalues the upstream business). Section 26 of the *PRRTA Regulation* provides the formula for the cost-plus price of assessable gas for a taxpayer in an integrated operation in a year of tax:

$$\frac{\text{(Upstream capital costs x Quantity coefficient)} + \text{Upstream operating costs}}{\text{Quantity of assessable gas}}$$ [46]

In plain language, the netback method starts downstream, from the LNG export sales (market price multiplied by gas volumes) point, and calculates the GTP by netting back proportional capital and operating costs including liquefaction – and divides the total by gas volume, less personal costs. Section 27 of the *PRRTA Regulation* provides the formula for the netback price of assessable gas for a taxpayer in an integrated operation in a year of tax:

End product value – (Downstream capital costs x Quantity coefficient) + Downstream operating costs) /
Quantity of assessable gas, minus, Downstream personnel costs /
quantity of taxpayer's downstream gas[47]

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46 *PRRTA Regulation* s 26:
quantity coefficient **[('QC')]** means:
(a) for an integrated operation that measures by volume—the volume coefficient for the year of tax; or
(b) for an integrated operation that measures by mass—the mass coefficient for the year of tax.
quantity of assessable gas means the quantity, measured by volume or mass, of the assessable gas that was produced in the operation in the year of tax.
upstream capital costs means the total amount of upstream capital costs incurred by the participants and allocated to the year of tax.
upstream operating costs means the total amount of upstream operating costs incurred by the participants in the year of tax.

47 *PRRTA Regulation* s 27 uses the following abbreviations:
EPVal - ((DCCxQC) + DOC) - DPC/ QTDG
Quantity of assessable gas
DCC (short for downstream capital costs) means the total amount of downstream capital costs incurred by the participants and allocated to the year of tax [and **QC**, see ibid].

The RPM is prescribed in sections 28 to 30 of the *PRRTA Regulation* with the RPM formula (to calculate the GTP) provided at section 24:

$$\frac{\text{Upstream 'Cost Plus' \$price} + \text{Downstream 'Netback' \$price}}{2}$$

The RPM method adds the cost-plus and netback prices together and then divides by two. Both prices will inevitably differ by what is called the residual value or economic rent. Economic rent comprises the value of fixed 'supply natural resource deposits; quasi-rents earned on short-term immobile inputs invested in exploration and lower production costs; and monopoly profits'.[48] This 50:50 split is supposed to 'equitably' split the economic rent between upstream and downstream to reflect the integrated nature of a gas project. The general theory to derive a GTP has been explained by Kellas. The RPM is illustrated in Figure 2. The RPM aligns with OECD transfer pricing guidelines, although they are not intended to consider domestic transfer pricing issues.[49]

DOC (short for downstream operating costs) means the total amount of downstream operating costs incurred by the participants in the year of tax.
DPC (short for downstream personal costs) means the total amount of downstream personal costs of the taxpayer for the year of tax.
EPVal (short for end product value).
QTDG (short for quantity of taxpayer's downstream gas.

48 The economic rent definition is from John Freebairn, 'Reconsidering Royalty and Resource Rent Taxes for Australian Mining' (2015) 59(4) *Australian Journal of Agricultural and Resource Economics* 586, 588.

49 Kellas (n 45). See also Arthur Andersen, *Report Prepared for Department of Primary Industries and Energy* (Report, July 1998). See *Transfer Pricing Guidelines* (n 45).

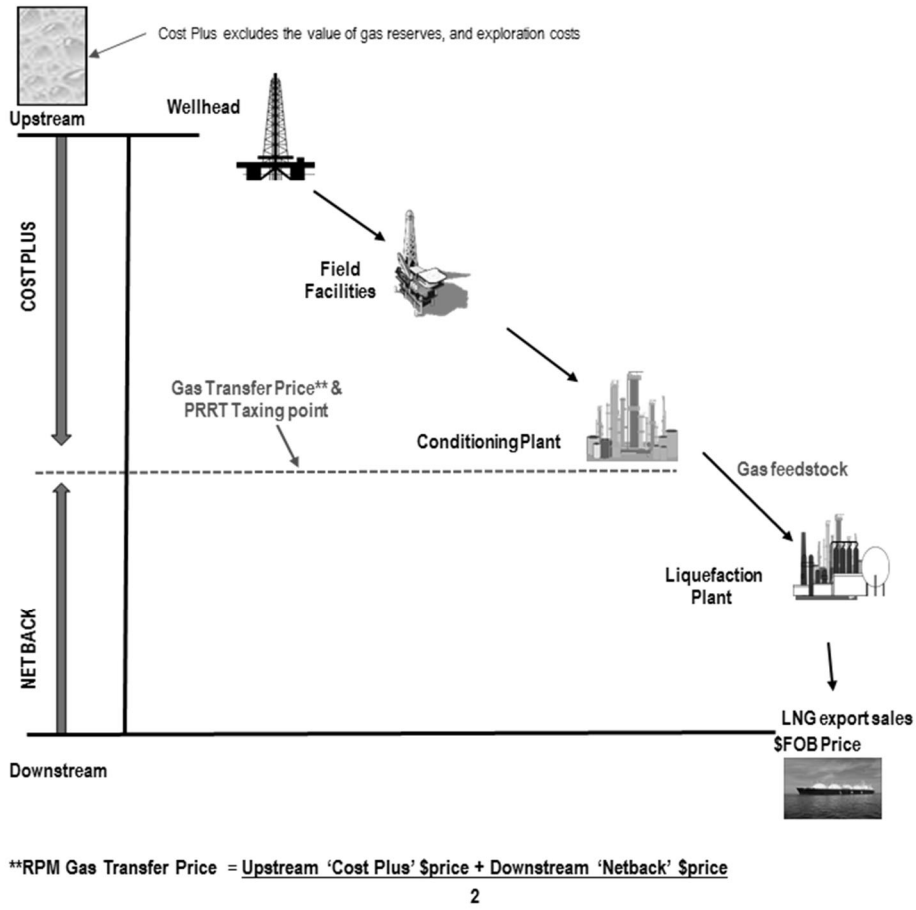

Figure 2: Integrated Gas Project: Regulation RPM to Calculate a GTP[50]

50 Diane Kraal, 'Senate Inquiry into Corporate Tax Avoidance: Australia's Offshore Oil and Gas Industry', *Tax and Transfer Policy Institute* (Article, 28 August 2017) <http://www.austaxpolicy.com/senate-inquiry-corporate-tax-avoidance-australias-offshore-oil-gas-industry/> (diagram modified).

The two GTP methods will be compared and discussed on the basis of which one presents pricing that is simpler, more transparent and efficient, and provides higher revenue.

To analyse the case study and modelling research findings, our framework is energy justice theory. This theory provides a decision-support tool for energy regulation by 'policy-makers to balance the energy trilemma of competing aims' from economics (such as gas transfer pricing methods), politics (such as energy security) and environment (such as the sustainability of gas and intergenerational equity).[51] The energy justice concept is depicted in Figure 3. Generally energy policy formulation, such as for gas, is 'dominated by economists and industry where economic costing is the prime tool used for decision-making'.[52] Energy justice emerged from, inter alia, the principle of distributive justice,[53] which for this research is the contention about the unequal allocation of the benefits of gas resources between the community as owners, and industry. Energy justice has been defined as 'a global energy system that fairly disseminates both the benefits and costs of energy' and includes procedural fairness, such as due process in energy decision-making as well as transparency and accountability.[54]

51 Diane Kraal, 'Petroleum Industry Tax Incentives and Energy Policy Implications: A Comparison between Australia, Malaysia, Indonesia and Papua New Guinea' (2019) 126 *Energy Policy* 212, 214.

52 Heffron and McCauley, 'The Concept of Energy Justice across the Disciplines' (n 16) 664.

53 Raphael J Heffron, Darren McCauley and Benjamin K Sovacool, 'Resolving Society's Energy Trilemma through the Energy Justice Metric' (2015) 87 *Energy Policy* 168, 169; Raphael J Heffron, Darren McCauley and Gerardo Zarazua de Rubens, 'Balancing the Energy Trilemma through the Energy Justice Metric' (2018) 229 *Applied Energy* 1911, 1193.

54 Sovacool et al (n 16) 4–5. See also Simon Marsden, 'The "Triangle" of Australian Energy Law and Policy: Omissions, Connections and Evaluating Environmental Effects' (2017) 29(3) *Journal of Environmental Law* 475.

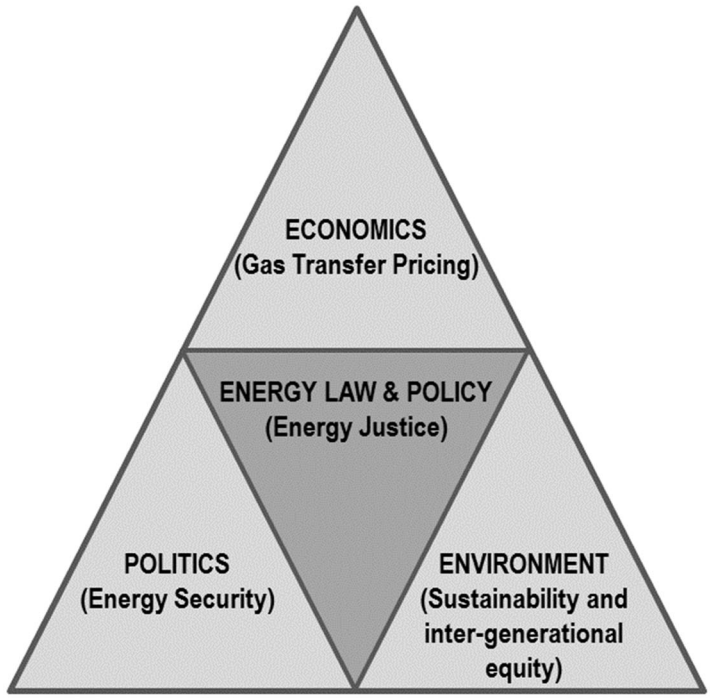

Figure 3: Energy Justice – The Triangle of Energy Law and Policy[55]

Energy justice might be seen as a variation on the triple bottom line concept (economic, social and environmental) and applied widely to extractive projects.[56] This research adapts both the energy justice energy law and policy triangle and the principles that underpin the energy justice framework to examine the Dutch experience with gas resources and Australia's experience with gas over the decades.[57]

IV CASE STUDY: THE DUTCH EXPERIENCE WITH GAS RESOURCES

This case study presents the findings for Dutch natural resource law (section A); its finances (section B); and the evolution away from regulated gas pricing to a gas market hub (section C). The latter section covers how the Dutch State

55 Source adapted from Heffron and McCauley, 'The Concept of Energy Justice across the Disciplines' (n 16) 665.

56 For triple bottom line: see Diane Kraal and Richard Nash, 'Minerals Resource Rent Tax (MRRT): Mining Project Evaluation Techniques' (2010) 14(1) *The Tax Specialist* 26, 26, 30.

57 There are a range of energy justice principles that include due process, transparency and accountability, sustainability, responsibility, transparency and accountability, intra- and intergenerational equity, availability and affordability. Some or all principles may be used: see Sovacool et al (n 16) 5.

maintained high revenues from its domestic gas production, but then environmental imperatives took precedence. This case study shows how energy justice provides an analytical frame that not only includes economics, but widens the discussion to the competing aims of politics and the environment.

A Dutch Natural Resources Law

The Dutch State is the owner of all natural resources and minerals from a depth of 100 metres. According to the *Mijnbouwwet* [Dutch Natural Resources Act] the government can outsource mining to a concession holder.[58] A concession holder has a monopoly on extracting the resource minerals and their revenues. Generally, a concession holder can autonomously develop a production plan. The Dutch State may only interfere under special conditions, including 'changed insights in the planned use or management of minerals, safety considerations and prevention of damage to properties'.[59]

Furthermore, a concession holder must take all reasonable measures to prevent activities that might result in damage.[60] The Resource Minister may stipulate that a security must be provided to cover any liability from damage caused by earth movement resulting from the extraction of minerals. The Resource Minister appoints a commissioner, *Technische commissie bodembeweging* [Technical commissioner on soil movement] whose main task is to advise and inform the Minister and potential affected inhabitants about damage caused by mining activities.[61] Finally, there is a fund, *Waarborgfonds mijnbouwschade* [Mining damage guarantee fund] from which damages are paid in cases where a responsible concession holder is insolvent.[62]

B Financial Importance of Gas

Since the discovery of the Groningen field in 1959, gas revenues have played an important role in the Netherlands' state budget. Most of the revenues from gas extraction go to the Dutch state (90%) and the rest to Shell and Exxon Mobil (10%).[63] The Groningen gas field has yielded about 288 billion euros for government coffers, whereas the gas extraction companies (ExxonMobil and Royal Dutch Shell) have earned 29 billion euros.[64] The national importance of the

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58 *Mijnbouwwet* (the Netherlands) [Dutch Natural Resources Act] art 143(2).

59 Ibid. Machiel Mulder and Peter Perey, 'Role of the Groningen Gas Field in the Gas Market' in Machiel Mulder and Peter Perey (eds), *Gas Production and Earthquakes in Groningen: Reflection on Economic and Social Consequences* (Centre for Energy Economics Research, University of Groningen, 2018) 11, 15 ('Role of the Groningen Gas Field').

60 *Mijnbouwwet* (the Netherlands) [Dutch Natural Resources Act] art 52g.

61 Ibid art 114.

62 Ibid ch 9.

63 These percentages refer to the Groningen gas field. For the small fields, the share of the Dutch state in the revenues is about 70%: Netherlands Court of Audit, *Use of Natural Gas Revenues: Facts, Figures and Scenarios* (Report, 2014) 16.

64 Bert Scholtens, 'The Janus Face of Natural Gas Resources in the Netherlands' in Machiel Mulder and Peter Perey (eds), *Gas Production and Earthquakes in Groningen: Reflection on Economic and Social Consequences* (Centre for Energy Economics Research, University of Groningen, 2018) 25, 25. André

gas fields becomes more apparent when looking at the value of natural gas revenue and its proportionate contribution to total government revenue (Figure 4).

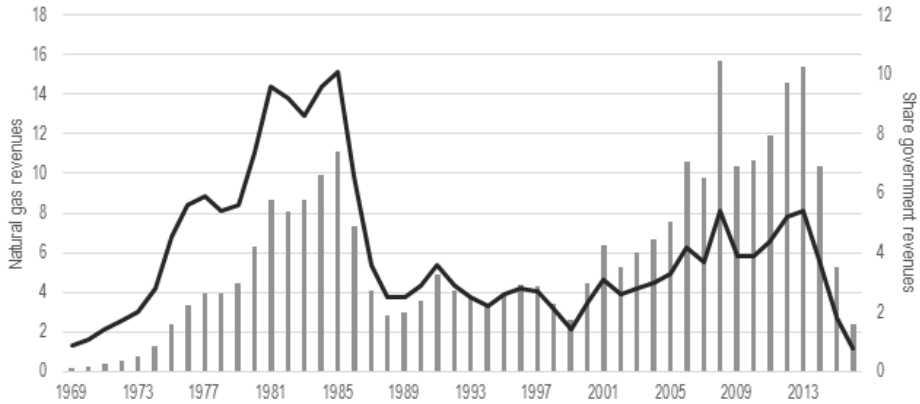

Figure 4: Natural Gas Government Revenue and Gas as a Percentage of Total Government Revenue[65]

C Dutch Gas Policy in Transition

This section presents the Dutch gas experience in four stages, while recognising the energy justice triangle of the competing aims of economics, politics and the environment. This trilemma is highlighted in the heading of the following sections by the use of some energy justice triangle principles: due process, transparency and accountability, sustainability, responsibility, transparency and accountability, intra- and intergenerational equity, availability, and affordability.[66]

1 Stage 1: Discovery and Rapid Implementation of Gas Grid in the Netherlands (Availability)

The Netherlands became one of the major gas producers in Europe after the discovery in 1959 of significant onshore gas reservoirs in the northern province of Groningen (initial magnitude about 2800 billion cubic metres ('bcm')). This gas field was unique in Europe in terms of both size and low-cost production. The Groningen field has flexibility in production that is quick and cheap. This enabled the Netherlands to maximise revenues from gas production by adapting the timing of production to the periods of high demand and, hence, higher prices. As the monopolistic supplier to Europe's gas markets from 1965, the Groningen

Mares, Frank Notten, Netherlands Bureau of Statistics (CBS), *De Nederlandse Economie in 2017* [The Dutch Economy in 2017] (Report, March 2018).

65 CBS, as cited in Scholtens (n 64) 26.

66 Sovacool et al (n 16) 5.

field earned supranormal profits for the Dutch state and the operators Royal Dutch Shell and Exxon.[67]

Initially, the Dutch policy was to base its prices for selling the gas on the regulated market value principle, where the gas price was based on the price of alternative fuels. Long-term contacts reflected this principle. An underlying rationale was that if gas prices were slightly below the prices of alternative fuels, users would have no incentive to switch to these alternatives, while the revenues from gas production would be maximised.[68] In this scenario, gas pricing was, as per contract prices set by the Dutch suppliers, not really a reflection of market-based gas pricing, as the gas price was unrelated to the actual supply and demand of gas, but related to the market price of alternative commodities.

Based on these market-value prices, the revenues for the gas producers (and their shareholders) were determined using the netback pricing principle, where initially fixed fees were used as compensation for the costs of the transportation and distribution network operator.[69] These fees were initially set by the unregulated monopolistic infrastructure operators, but later on, with the introduction of access and tariff regulation, the fees were set by the regulator using economic criteria to set tariffs related to efficient costs. The latter development resulted in higher net profits because of the gradual decline in regulated infrastructure tariffs.

In the 1960s, the Dutch community switched to natural gas as its main energy source, with gas availability facilitated by the legislative requirement that distribution grid operators provide every household a connection to the gas grid.[70] Thus the domestic transition to gas happened rapidly. After 1966, as a result of the strong increase in both domestic gas consumption and exports, the production from the Groningen field grew rapidly into the 1970s (Figure 5).

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67 Charles Vlek, 'Induced Earthquakes from Long-Term Gas Extraction in Groningen, the Netherlands: Statistical Analysis and Prognosis for Acceptable-Risk Regulation' (2018) 38(7) *Risk Analysis* 1455, 1455; Mulder and Perey, 'Role of the Groningen Gas Field' (n 59) 12–13. Supranormal profits exceed normal profits as compensation for costs of capital.

68 Aad F Correljé and Peter R Odell, 'Four Decades of Groningen Production and Pricing Policies and a View to the Future' (2000) 28(1) *Energy Policy* 19; Stern (n 17) 44–5.

69 See Aad Correljé, Coby van der Linde and Theo Westerwoudt, *Natural Gas in the Netherlands: From Cooperation to Competition?* (Oranje-Nassau Groep, 2003) 140.

70 Only recently has this legal obligation been removed from the *Gaswet* (the Netherlands) [Dutch Gas Act] art 10(6) because of the government policy to switch to alternative sources for household heating (eg, heat pumps and district heating).

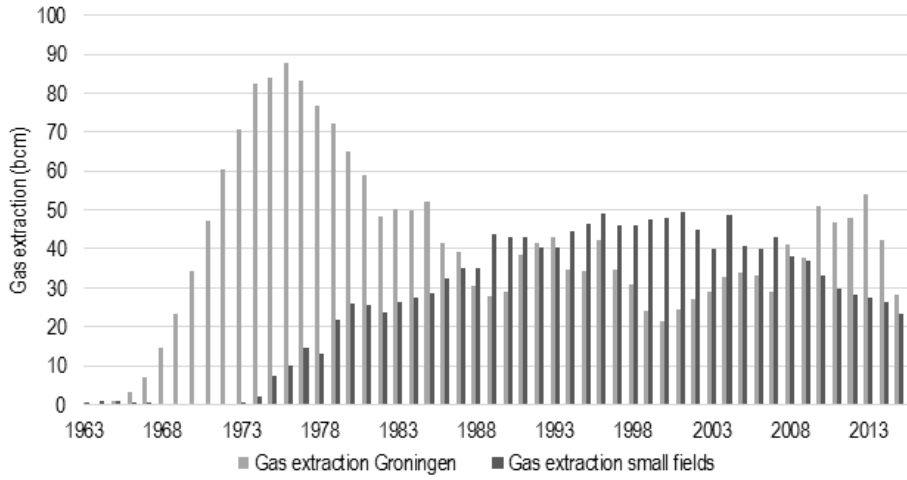


Figure 5: Gas Production by Fields in the Netherlands, 1963–2016[71]

2 *Stage 2: Capping Production after Oil Crises (Sustainability of Supply)*

The 1970s oil crisis drove Western countries to rethink their energy policies, underlining the strategic importance of natural resources. The Netherlands was no different, and in the following decade its approach towards domestic natural resources altered significantly, with the Groningen gas field suddenly of huge strategic importance for energy independence. In 1974 Dutch energy policy was transformed with the 'introduction of the *Kleineveldenbeleid*, an offtake guarantee for small fields',[72] both offshore and onshore;[73] while Gasunie, 'the incumbent operator of the Dutch gas system',[74] was required to accept all gas produced from small fields before purchasing gas from the Groningen field.[75] This offtake guarantee policy had the consequence of higher revenues from these small fields, resulting in the Groningen gas field to be preserved and used flexibly and more sustainably. Figure 5 shows the extent to which the offtake guarantee led to lower Groningen gas field production levels from 1974.

71 NAM and CBS, as cited in Mulder and Perey (n 59) 13.

72 Mulder and Perey, 'Role of the Groningen Gas Field' (n 59) 12.

73 Machiel Mulder and Gijsbert Zwart, CPB Netherlands Bureau for Economic Policy Analysis, *Government Involvement in Liberalised Gas Markets: A Welfare-Economic Analysis of Dutch Gas-Depletion Policy* (Report No 110, February 2006) ('*Government Involvement in Liberalised Gas Markets*').

74 Mulder and Perey, 'Role of the Groningen Gas Field' (n 59) 12.

75 *Gaswet* (Netherlands) [Dutch Gas Act] art 54; Mulder and Zwart, *Government Involvement in Liberalised Gas Markets* (n 69) 22; Mulder and Perey, 'Role of the Groningen Gas Field' (n 59) 12.

Production out of Groningen fields until the early 2000s was regulated by a 'maximum allowed' policy of 80 bcm and applied to all Dutch gas fields.[76] Thus, the maximum Groningen production permitted was determined by this maximum minus the actual production of smaller fields.[77] As the production of small fields was expected to decline quickly, and in order to prevent the rapid depletion of the Groningen gas field, its production was capped. The policy practicalities, given concerns over sustainability of supply, led to a cap on the production level of the Groningen field over a 10 year timeframe.[78] For instance, in 2006–15, the cap was preset at 425 bcm over 10 years, with no annual restriction. Thus, the producer could freely select a yearly production level insofar as the 10 years cap of 425 bcm would not be exceeded.

3 Stage 3: Liberalisation of Gas Markets (Affordability)

In the 1990s, the European Union started to liberalise its gas markets, replacing the early Dutch regulations that mechanistically set the gas price by competitive gas wholesale markets. The European Union goal was to foster competition to encourage affordable domestic and commercial retail prices.

In 2003 the liberalisation of the gas market in Europe took off with the EU Directive 2003/55/EC of the European Parliament and of the Council of 26 June 2003.[79] It concerned common rules for the natural gas market. This directive gave gas consumers the right to conclude gas delivery contracts with the supplier of their choice, while producers obtained the right the sell the gas to whom they preferred. In order to facilitate this process, both producers and consumers got the right to use the gas infrastructure (Third Party Access).[80] The next directive followed in 2009,[81] which imposed rules regarding the independence and unbundling of network (transport, distribution and storage) operators. Also, rules were set regarding the access conditions for these networks and how the infrastructure should be regulated.

The liberalisation of European gas systems led, inter alia, to the implementation of the TTF in the Netherlands. The TTF is a virtual hub based on an entry-exit system where market parties can transfer gas that is within the national grid to other parties. While the gas is in the system, ownership can change. It is quite common for gas ownership to change often between the entry and exit point. Each change of gas owner in the grid requires a title transfer to be

76 Mulder and Perey, 'Role of the Groningen Gas Field' (n 59) 14.

77 Ibid.

78 LJ Brinkhorst, Minister of Economic Affairs, *Voorzienings- en Leveringszekerheid Energie* [Energy Supply and Energy Security] (Parliamentary Document 29023 No 21, House of Representatives, the Netherlands, 22 December 2005); Mulder and Perey, 'Role of the Groningen Gas Field' (n 59) 16.

79 *Directive 2003/55/EC of the European Parliament and of the Council of 26 June 2003 Concerning Common Rules for the Internal Market in Natural Gas and Repealing Directive 98/30/EC* [2003] OJ L 176/57.

80 For an extensive analysis of this process: see Correljé, van der Linde and Westerwoudt (n 66) 141.

81 *Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 Concerning Common Rules for the Internal Market in Natural Gas and Repealing Directive 2003/55/EC* [2009] OJ L 211/94.

reported to the operator of the national grid, Gasunie Transport Services. In this way, the operator always knows the commodity owner. This title registration function of the TSO is meant to facilitate the trading of gas. Since the introduction of the TTF in 2003, gas is not only traded in bilateral contracts between producer and consumer and in spot markets, but increasingly also on multiple exchanges. The increase in the fluidity of the gas market can be measured by the higher number of trades (referred to as the churn rate) of a physical amount of gas, the large number of traders and the negligible effect of one trade contract on the market outcomes.[82]

To sell the commodity as a homogenous product, each type of gas is valued not by volume, but by the energy content it carries, denoted by lower to higher calorific values. This value mechanism is appropriate given heating is the main use of gas. This system of valuation uniformity enables the Dutch grid to be connected to other European grids, creating a well-integrated European gas market. For instance, the Dutch TTF is connected to the Zeebrugge hub (Belgium), NetConnect (Germany) and NBP (UK).

Together with the development of European gas hubs, the pricing scheme for gas in export contracts has changed. Prices have been increasingly based on gas hub prices, rather than oil-linked long-term contracts. This connection to hub prices is the outcome of the international integration of gas hubs enabling market parties to resell gas acquired through long-term contracts on short-term markets. Although hub prices are still related to oil prices, this relationship has become less significant. Further, gas prices are increasingly related to the fundamentals in the gas market, such as outside temperatures.[83] The increase in market fluidity and the international integration of gas markets have resulted in more efficient pricing, strongly related to the demand and supply situation and the marginal costs of supply. The influence of individual suppliers has thus been reduced. This improvement in efficiency in gas pricing has positively influenced the affordability of gas for consumers because there is less room for strategic behaviour by individual suppliers to raise the price in times of scarcity.

4 Stage 4: Further Capping of Production Due to Earthquake Risk (Intergenerational Equity)

Over the past 25 years the Groningen area has been subject to many earthquakes (Figure 6). In August 2012 an earthquake, of magnitude 3.6, occurred in northern Groningen. Immediately after the incident, a spike in complaints about damage to houses were recorded. The field operator received well over 1,000 damage reports from shortly after the earthquake. Research showed that the earthquake was linked to gas extraction activities from the

82 The churn rate on the TTF is about 10, which means that the ownership has changed about 10 times before the gas is actually withdrawn from the system. This relatively high churn rate is a sign of a liquid market.

83 Daan Hulshof, Jan-Pieter van der Maat, and Machiel Mulder, 'Market Fundamentals, Competition and Natural-Gas Prices' (2016) 94 *Energy Policy* 480, 481, 485.

Groningen gas field.[84] Since this incident, over 100 earthquakes of 1.5 or more on the Richter scale have been registered and there has been a sharp rise in the number of damage reports to homes. Since the start of 2018, over 79,000 local damage claims had been filed.[85] By international comparison, the damage levels in Groningen was higher than normal, given the moderate magnitude readings of the earthquakes.[86]

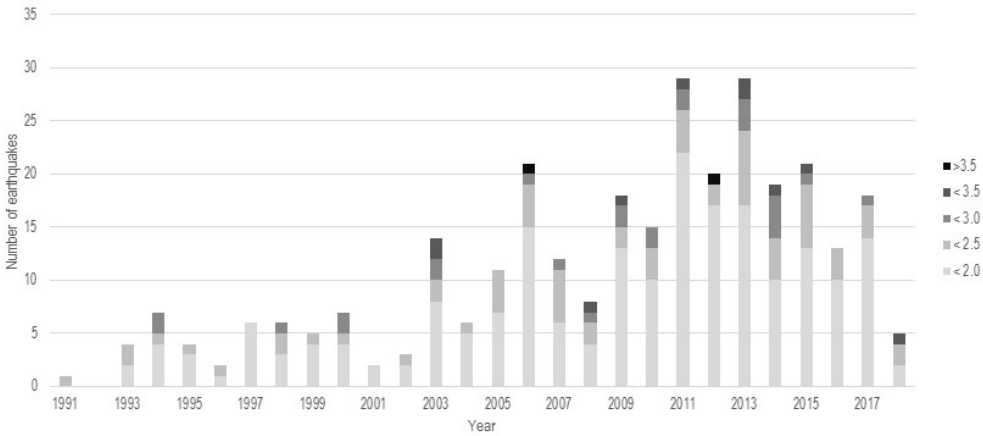


Figure 6: Total Number of Earthquakes in the Groningen Region with a Magnitude >1.5 per Year, Categorised by Magnitude, 1991–2018[87]

In response to gas extraction-induced earthquakes, the Dutch government introduced a policy of lower gas production levels, directed at mitigating future risks of earthquakes and environmental damage. Thus, from 2015, the government restricted the annual level of production from the Groningen field[88] by reducing the initial cap of 425 bcm over a period of 10 years to an annual cap of 27 bcm. However, after subsequent and more regular earthquakes and tremors, the cap has since been lowered several times. Nonetheless, when the weather is abnormally cold in the Netherlands, production is allowed to increase to secure domestic supply and prevent an energy shortage. In June 2017 the Dutch Minister of Economic Affairs announced the abandonment of the 'access to gas grid' legislation to enable the transition of energy from fossil fuels, such as

84 Bernard Dost and Dirk Kraaijpoel, KNMI, *The August 16, 2012 Earthquake near Huizinge (Groningen)* (Report, January 2013) 5.

85 HJG Kamp, Minister for Economic Affairs, 'Gaswinning' (Parliamentary Document No 33 529/212, House of Representatives, the Netherlands, 18 December 2015) 3.

86 Torild van Eck et al, 'Seismic Hazard Due to Small-Magnitude, Shallow-Source, Induced Earthquakes in The Netherlands' (2006) 87(1–2) *Engineering Geology* 105.

87 NAM, as cited in Machiel Mulder and Peter Perey, 'Introduction' in Machiel Mulder and Peter Perey (eds), *Gas Production and Earthquakes in Groningen: Reflection on Economic and Social Consequences* (Centre for Energy Economics Research, University of Groningen, 2018) 5, 6.

88 Kamp (n 85).

natural gas, to renewable energy sources, with the aim of significantly reducing CO_2 emissions.[89]

In March 2018 the Dutch government determined that the production of gas from the Groningen field would cease by 2030.[90] The 'access to grid' change, in combination with the end of gas production in Groningen, is intended to lead to a fundamental change to renewables, with natural gas being replaced by electric heat pumps as the primary source of household heating. This environmental catastrophe had intergenerational equity as the central principle in the decision to cease production. The next Part turns to the economic modelling and findings for the selected gas projects in Australia.

V MODELLING AND FINDINGS: AUSTRALIAN GAS PROJECTS

We test the hypothesis that government PRRT revenue would increase from an alternative method of calculating the GTP. We model the current method from the Australian *PRRTA Regulation* for gas transfer pricing and the proposed netback method; and compare the results. Sections A and B describe the model and variables, while section C presents the findings.

A The FARI Model

The FARI excel model, has been used for modelling. It is Excel-based and primarily used. The Fiscal Affairs Department of the IMF owns the FARI model and uses it for revenue forecasting and work on fiscal regime design and analysis of mineral resource industries. It provides government and investor revenue analysis, and pre- and after-tax net cash flows. The standard version of FARI became publicly available in 2016.[91] For this research, FARI has been adapted for the Australian fiscal regime, specifically to calculate revenue outcomes from the PRRT.

1 Projects for Modelling

The integrated gas projects for modelling are the Inpex's Ichthys LNG, the Woodside Petroleum's Pluto LNG and the Chevron's Wheatstone LNG and Gorgon LNG projects.[92] These projects have been selected because of their gas

89 See Minister of Economic Affairs, 'Verplichte Gasaansluiting Voor Nieuwbouwwoning Vervalt [Mandatory Gas Connection for New-Build Home Expires]' (News Release, 27 June 2017).

90 Eric Wiebes, Minister of Economic Affairs and Climate Policy, 'Kamerbrief over Gaswinning Groningen [Archived Letters to Government]' (Letter, 29 March 2018) 8 <https://www.rijksoverheid.nl/onderwerpen/gaswinning-in-groningen/documenten/kamerstukken/2018/03/29/kamerbrief-over-gaswinning-groningen>.

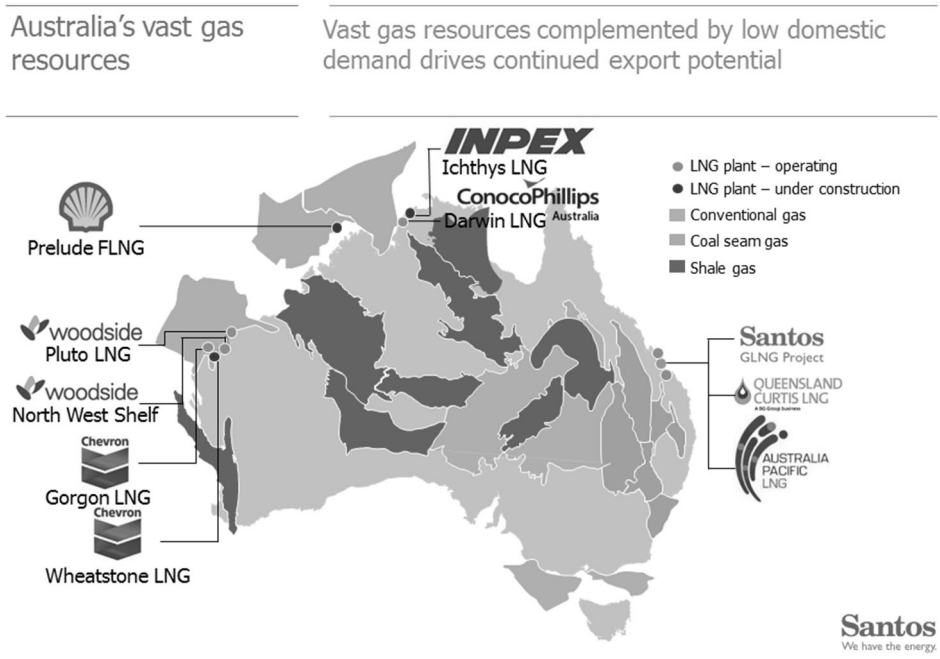
91 Oana Luca and Diego Mesa Puyo, Fiscal Affairs Department, *Fiscal Analysis of Resource Industries (FARI) Methodology* (Technical Notes and Manuals No 16/01, International Monetary Fund, February 2016). For more on previous applications of the FARI model: see Kraal, 'Review of Australia's PRRT' (n 9) 329–30.

92 The latest project fact sheets are: 'Ichthys LNG Project', *Inpex* (Web Page) <https://www.inpex.com.au/our-projects/ichthys-lng-project/>; 'Pluto LNG', *Woodside* (Web Page)

production size and as being within the PRRT regime. Figure 7 shows the locations of the largest LNG projects in Australia, which are in waters off north-west Australia and under Australian federal jurisdiction. Effective 1 July 2019, the (east coast) onshore, coal seam gas projects are removed from the PRRT.[93]

<https://www.woodside.com.au/our-business/pluto-lng>; 'Wheatstone Project: Australia's First Natural Gas Hub', *Chevron Australia* (Web Page) <https://australia.chevron.com/our-businesses/wheatstone-project>; 'Gorgon Project: An Australian Icon', *Chevron Australia* (Web Page) <https://australia.chevron.com/our-businesses/gorgon-project>.

93 'Government Response' (n 11).



	PROJECT NAME							
			for model	for model	for model	for model		
	Prelude*	Darwin LNG[b]	Ichthys LNG*	Pluto LNG*	Wheatstone LNG*	Gorgon LNG*	North West Shelf LNG	East coast: three coal seam gas projects +
PRRT (Cth)	yes	no	yes	yes	yes	yes	yes	from 1/7/19, no
Gas production: millions of tonnes per annum (MTPA)	3.6	3.6	8.9	4.9	8.9	15.6	16.3	25.3

* Project natural gas from offshore waters, under Commonwealth (federal) jurisdiction.
\+ Project coal seam gas from onshore, under state jurisdiction. Onshore gas removed from PRRT from 1/7/19.
b Project natural gas project from offshore waters, under both Australia and Timor Leste jurisdiction

Figure 7: LNG Projects[94] and Legend

94 Santos Ltd, with permission.

2 PRRT Methods for Testing

Integrated gas projects in Australia are subject to a range of taxes, including a rent tax under the *PRRTA Act*.[95] Under the *PRRTA Regulation* a method is prescribed for calculating the GTP,[96] an element in the calculation of a taxpayer's PRRT taxable profit. Data from each project is used to model two scenarios:

(i) PRRT revenue to government based on the current *PRRTA Regulation* RPM.[97] This is the base case.

(ii) PRRT revenue to government based on the proposed 'netback' method using market prices. There are many variations of elements in a formula for the netback method, and we have based this netback on the formula described at Section 27 of the *PRRTA Regulation*.[98]

B Data

1 Production and Costs

Wood Mackenzie project economics data is the source of inputs used for modelling. The data is proprietary from this internationally recognised and reputable data collection company.[99] Data from 2017 is used for the four selected projects. Production data inputs to FARI include volumes of export gas, domestic gas, and condensate. Expenditure includes capital, operating and exploration costs for PRRT calculations. Exploration costs are excluded from RPM calculations.

2 Fiscal: Tax Rates

The company income tax rate and its depreciation rates for capital assets; and the petroleum resource rent tax rate are inputs.

3 Economic: Inflation and Discount Rates

The fiscal calculations are performed in nominal and real terms.[100] One inflation rate of 2% is input and from 2018 compounded annually; it is applied to revenues, costs and prices. A range of discount rates are available for net present value calculations.

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95 Other taxes include company income tax and dividend withholding tax: *Income Tax Assessment Act 1997* (Cth); *Income Tax Assessment Act 1936* (Cth); *Income Tax (Dividends, Interest and Royalties Withholding Tax) Act 1974* (Cth).

96 The GTP is defined above in Part I(A).

97 The 'residual price' method is defined above in Part III. See also, Kraal, 'Review of Australia's PRRT' (n 9) 339.

98 The 'netback' method is defined above in Part III.

99 Wood Mackenzie, <https://www.woodmac.com/>. Other investigators can, in principle, independently obtain the data used in this modelling.

100 The term 'real' means constant dollars, and 'nominal' means inflation is included in the calculation.

4 Economic: Financing Assumptions

Project financing assumptions are fields for input. However, no project finance is assumed.

5 Economic: Prices

Scenario (i) modelling uses the RPM to calculate a GTP to value of the feedstock gas at the taxing point, before gas transfers to the liquefaction plant. As the GTP for the selected gas projects is not publicly available, it is derived using FARI.[101]

Scenario (ii) modelling uses the netback method to calculate a GTP and is derived using FARI. It requires LNG market prices (taken from Wood Mackenzie data). Pricing for LNG usually has three parts: a fixed component that is negotiated, the Japanese Crude Cocktail ('JCC') that is published, and a fraction that is negotiated and used to multiply the JCC, normally at a discount.[102] Set floors and ceilings can be included as part of the JCC component.

C Findings: Modelling of the Selected Projects, Australia

A technical explanation of the prescribed *PRRTA Regulation* residual price method (to calculate the GTP) in the FARI model, and a snapshot of the findings on GTP for Woodside Petroleum's Pluto LNG project (from 2008 to 2017) is provided in the Appendix.

The four integrated LNG projects were modelled from the start of production to 2030. Figure 8 shows the findings from the FARI model under the current *PRRTA Regulation* RPM. First, for the years 2012–30 only the Gorgon and Ichthys projects generate USD5.5 billion (ie, minor) PRRT revenue for the Government, as indicated by the graph columns. Second, the GTP per project, indicated by the graph lines, tends to rise toward the end of project life, a function of increased capital costs in upstream activities over the project.[103]

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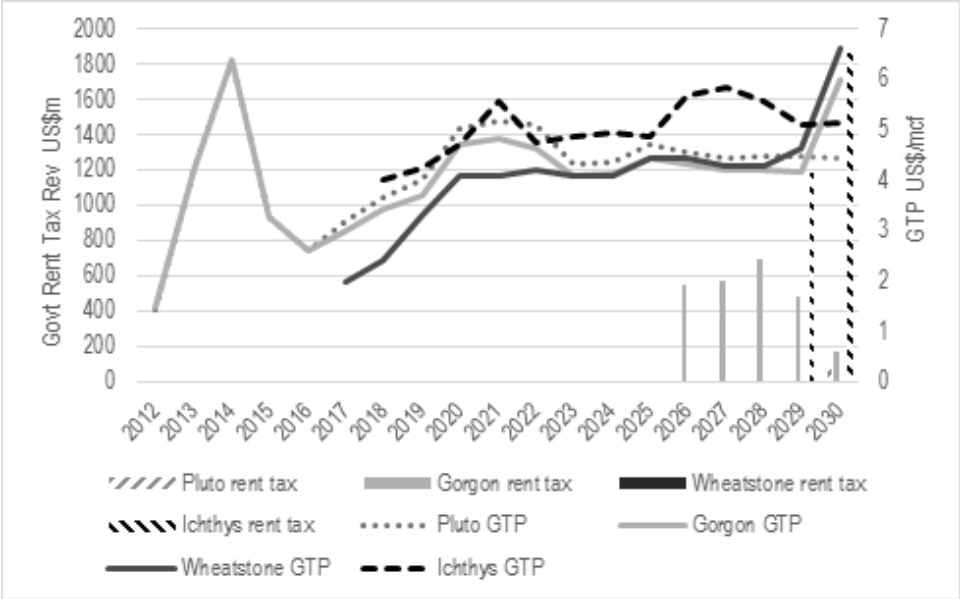
101 The GTP is defined above in Part I(A). The GTP calculations are based on guidance from an Australian Taxation Office ruling: Australian Taxation Office, *Petroleum Resource Rent Tax: Application of Petroleum Resource Rent Tax Assessment Regulations 2005 to an Integrated Gas-to-Liquid Operation* (Taxation Ruling, TR 2008/10, 17 December 2008).

102 Howard V Roger and Jonathan Stern, *Challenges to JCC Pricing in Asian LNG Markets* (Paper No NG 81, Oxford Institute for Energy Studies, February 2014) 44.

103 Note that the price spikes for the Gorgon project over the years 2012 to 2016 are due to the Fukushima nuclear plant disaster in 2011. There was an immediate demand increase from Japan for Australian LNG: '2011 Japan Earthquake: Tsunami Fast Facts', *CNN* (Web Page) <https://edition.cnn.com/2013/07/17/world/asia/japan-earthquake---tsunami-fast-facts/index.html>. See 'Japan: Liquefied Natural Gas (LNG)' (n 36).

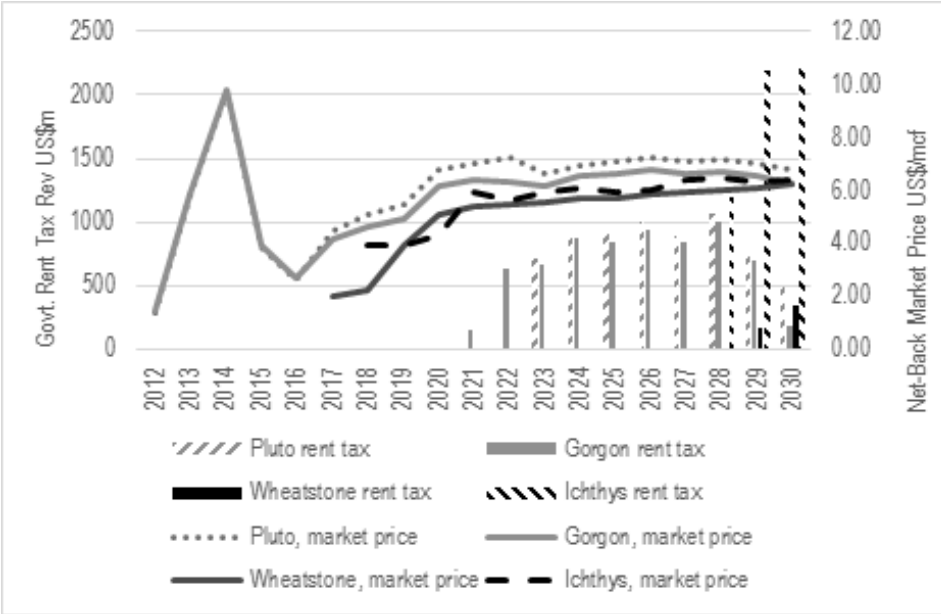


Data Table, 'snapshot', Government Rent Tax, $US millions (columns)							
	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**Total**
Pluto rent tax	0	0	0	0	0	66	66
Gorgon rent tax	0	551	574	692	484	166	2,467
Wheatstone rent tax	0	0	0	0	0	0	-
Ichthys rent tax	0	0	0	0	1184	1863	3,047
							$5,580
Data Table, 'snapshot', Gas Transfer Prices, US$/mcf (lines)							
	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**AVE price**
Pluto GTP	4.69	4.56	4.45	4.47	4.48	4.47	4.52
Gorgon GTP	4.45	4.31	4.19	4.20	4.15	6.02	4.55
Wheatstone GTP	4.42	4.43	4.27	4.29	4.64	6.64	4.78
Ichthys GTP	4.85	5.67	5.86	5.56	5.11	5.13	5.37
							4.81

Figure 8: Australian Government Rent Tax Revenue and Current RPM Regulated GTP, 2012–2030[104]

104 Authors, from FARI model and Wood Mackenzie data.

Figure 9 shows the findings from the FARI modelling using the proposed netback method. First, in looking at all project findings for PRRT revenue for the years 2012–30, as indicated by the graph columns, the netback method facilitates USD15.5 billion in tax revenue, compared to the lower revenue under the current RPM of USD5.5 billion (see Figure 8). Second, the GTPs based on the netback method per project, as indicated by the graph lines, are higher than the current RPM (also see Figure 8).



Data Table, 'snapshot', Government Rent Tax, $US millions (columns)							
	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**Total**
Pluto rent tax	902	1000	890	1069	736	492	5,090
Gorgon rent tax	850	945	840	1008	702	182	4,527
Wheatstone rent tax					34	311	345
Ichthys rent tax				1200	2185	2211	5,596
							$15,557
Data Table, 'snapshot', Net-Back Market Prices, US$/mcf (lines)							
	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**AVE price**
Pluto, market price	7.10	7.23	7.08	7.17	7.03	6.76	7.06
Gorgon, market price	6.66	6.78	6.62	6.69	6.53	6.25	6.59
Wheatstone, market price	5.72	5.85	5.95	6.04	6.09	6.23	5.98
Ichthys, market price	5.92	6.02	6.38	6.49	6.32	6.43	6.26
							6.47

Figure 9: Australian Government Rent Tax Revenue and GTP on Proposed Netback Method, 2012–2030[105]

105 Authors, from FARI model and Wood Mackenzie data.

VI ANALYSIS

A The Economics

1 The Netherlands

A key point from the Dutch case study is that state revenues did not fall when the Netherlands government shifted from regulated pricing to market pricing for its gas. Returns to the shareholders, which includes the State, remained high to the 1980s because the Groningen gas field had relatively low marginal costs.

The contribution of natural gas revenue to total Netherlands government revenue has lowered since, because of the extraction-related earthquakes and societal pressure to cap gas production. In the 'Stage 4' capping of production section of this article we note that the government policy to contain future damage from gas extraction was decisive. Legislation to progressively end Groningen gas production will have a profound impact on the national budget.

The shift away from regulated gas pricing resulted in more efficient pricing. The influence of individual companies on gas pricing has been reduced as there is less room for strategic behaviour to raise the price in times of scarcity. A lesson from the Dutch nonetheless is their political decisiveness in pricing policy changes for efficiency and better economic outcomes.

2 Australia

This article proposes a shift to an alternative method of determining GTP (rather than shifting to market hub pricing). The economic case for change from the current *PRRTA Regulation* RPM to the netback method – is supported by the modelling of the four, large integrated gas projects in Australia. Revenue findings for the years 2012 to 2030 show total PRRT proceeds under the proposed netback method as USD15.5 billion,[106] compared to USD5.5 billion under the current RPM.

Price findings show the proposed netback method results in a higher average price of USD6.47/mcf compared to the current RPM method, which realises an average price of only USD4.81/mcf. Under the RPM, low prices in a project's early life allow a long accumulation of uplifted, carried-forward expenses that decrease the overall collection of PRRT revenue. As a general rule, a government should prefer to see the upstream transfer price as high as possible.

The reason for the differences can be seen in the RPM design. The RPM calculates the average price from two methods – cost-plus and netback (as defined above in the methodology section) to derive a GTP. However, the cost-plus method excludes the value of gas reserves as well as exploration costs, thus has little or no 'taxable profit' component (ie, economic rent).[107] When the cost-plus price is compared to the netback price, the former will almost always be lower. The notional GTP is further reduced by the RPM averaging process, due

106 Based on Wood Mackenzie prices.

107 Diane Kraal, Submission to the Australian Treasury, *Petroleum Resource Rent Tax: Review of Gas Transfer Pricing Arrangments* (3 June 2019) 5 ('Submission to Treasury').

to the exclusion of the rent from petroleum reservoir at the wellhead, and exploration costs.

Upstream activities 'encounter the most risks, including geological (exploration), reservoir and technology risks'. Producers will 'usually seek a proportionally higher share of the rewards as a result'.[108] These returns on the original development of a petroleum field are 'quasi rents',[109] but there are also quasi rents on the downstream side of the value chain, such as technology risks.

Thus, taking into account the modelling and the need to apply the PRRT on 'taxable profits' (economic rent) the netback method alone could provide a fairer price between owners and industry, and our findings suggest higher tax revenue. The current RPM is seen to advantage industry to the detriment of the community that owns the gas resources. Some might argue that the RPM overcomes supplier tendency to overstate cost-plus expenses and understate the netback expenses because the RPM takes the average of both methods. However, a government audit process is applied to gas project revenues.[110] A change to the proposed netback method for the PRRT GTP would also harmonise all resource calculation methods around Australia. The netback method is used in Western Australia's North West Shelf project and for east coast gas royalty calculations (for example, Gladstone LNG).

Generally, the current RPM method lacks simplicity and transparency. The Netherlands found that the lack of transparency under its early pricing system encouraged strategic behaviour by individual suppliers. In Australia, section 20(5) of the *PRRTA Regulation* is underpinned by a flawed RPM principle that 'outcomes should be assessed against economic efficiency criteria':[111]

> It is an outdated 20th century principle that preferences the economics of a resource project, possibly originating from the UK *non-proprietorial* model of oil and gas governance. Under the UK model, 'investors name their price' to extract resources, and government entices capital inflow through tax concessions. Contrast the US *proprietorial* model of oil and gas governance. Under the US model, mineral resources are seen as valuable and it is private investors that have to adapt accordingly.[112]

In the US, minerals below private land are acknowledged for their intrinsic value, and paid for promptly upon extraction via a royalty. For example, the Queensland State government levies a petroleum royalty in a similar way.

The proposed netback method to determine the GTP could provide an interim solution in lieu of the absence of an Asia-Pacific gas market hub. Up to the 1990s, gas pricing in the Netherlands moved 'increasingly out of line with both

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108 Kellas (n 45) 166.

109 Ross Garnaut, 'Principles and Practice of Resource Rent Taxation' (2010) 43(4) *Australian Economic Review* 347, 348–9.

110 See, eg, Australian National Audit Office, *Collection of North West Shelf Royalty Revenue* (Report No 28, 28 November 2016).

111 Treasury (Cth), 'Review of the PRRT Gas Transfer Pricing Arrangements' (Consultation Paper, Commonwealth, April 2019) 4.

112 Kraal, Submission to Treasury (n 107) 8 (citations omitted), quoting Juan Carlos Boué, *The UK North Sea as a Global Experiment in Neoliberal Resource Extraction: The British Model of Petroleum Governance from 1970–2018* (Platform London and Public and Commercial Services Union, 2018) 22.

economic and market fundamentals' and required change.[113] The same is true for Australia.

As the government-instigated GTP review progresses through to 2020,[114] it is anticipated that industry will again raise the issue of 'sovereign risk' in response to calls for tax reform, however as discussed, such risk concerns are overstated. Sovereign risk is characterised by overt changes, such as nationalisation of resources, certainly not by tax regulatory changes.[115] In the Coalition 1978 budget, Prime Minister Malcom Fraser immediately brought in parity pricing for petroleum for current resource projects, for example, Bass Strait. In effect it was a tax, immediately raising government revenue. Petroleum companies stayed in Australia and continued investing; they made no claims of sovereign risk. With the foreshadowed changes to the PRRT announced in November 2018,[116] there was silence from industry on sovereign risk. Peter Coleman, Woodside CEO, stated, that the Government should 'swiftly enshrine recent [PPRT] reforms'.[117]

The Netherlands government acknowledged the economic importance of gas revenues to its national budget but was politically motivated to end of gas extraction by 2030. In Australia, budget forward estimates of low PRRT revenues is still a national issue. Political decisiveness is required in the wake of the *Callaghan Report* and Senate review.[118] The 21st century expectation is that the evaluation of fossil fuel extraction projects should not only be based on economic principles. Factors other than economics need to be considered, as covered next.

B Energy Justice

In addition to the economics of gas pricing issues, politics (energy security) and the environment (sustainability and intergenerational equity) have been pressures that pull government policy in different directions.[119] Thus economics, politics and environmental issues form what energy justice refers to as the trilemma of competing aims. This section applies some of the energy justice operational principles (availability, affordability, due process, transparency and accountability, sustainability, responsibility and intra- and intergenerational equity).[120] We discuss how gas has evolved in Australia and the much-needed

113 Stern (n 17) 44.

114 'Government Response' (n 11).

115 Giovanni Di Lieto, 'Why Australia Doesn't Face Sovereign Risk in the Gas Markets', *The Conversation* (online, 27 September 2017) <https://theconversation.com/why-australia-doesnt-face-sovereign-risk-in-the-gas-markets-84686>.

116 'Government Response' (n 11).

117 Peter Ker, 'Woodside Boss Peter Coleman Says Don't Dither on PRRT Reform', *Australian Financial Review* (online, 13 November 2018) <https://www.afr.com/business/energy/gas/woodside-boss-peter-coleman-says-dont-dither-on-prrt-reform-20181109-h17q31>.

118 *Corporate Tax Avoidance Report* (n 10); *Callaghan Report* (n 8).

119 The current Morrison government has declined to commit to the previous National Energy Guarantee ('NEG') and now has an energy policy focus on lower prices and reliable energy: 'Our Plan', *Liberal Party of Australia* (Web Page) <https://www.liberal.org.au/our-plan/energy>. See also, Prime Minister and Minister for the Environment, 'Meeting Our Climate Commitments Without Wrecking the Economy' (Media Release, 25 February 2019).

120 Sovacool et al (n 16) 5.

reform of its prescribed RPM method as per regulation 20 of the *PRRTA Regulation* to the proposed netback method. We draw on the case study of the Dutch experience for comparison.

The 1960s commencement of gas production in the Netherlands enabled the availability of this resource domestically. This decade saw the government determine the gas price by regulation, where the gas price was based on the price of alternative fuels, enabling the State to reap supranormal profits. Equally for Australia, from 1969 gas became available for domestic consumption and prices were affordable.[121]

With the oil crisis of the 1970s, Dutch politics took precedence. Energy security arising from concerns about supply shortages and intergenerational equity saw the Netherlands cut and preserve its gas production. The policy practicalities looked to sustainability of supply and led to capping Groningen field production levels over 10-year timeframes. In Australia, generally federal royalties were replaced by the *PRRTA Act* under the principle of encouraging investment in petroleum exploration and development by delaying taxation,[122] and to facilitate energy security in the wake of the oil crisis.[123] Environmental concerns about greenhouse gas emissions were not a global issue at that time.[124]

In the 1990s gas affordability became a central issue in the Netherlands. High gas prices borne by domestic and commercial customers were due to the regulated and mechanistic market-value principle. The term 'market value' proved to be a misnomer, and the discarding of that principle was part of the liberalisation of the Dutch gas market. The result has been more efficiency in gas prices, with less room for strategic behaviour by suppliers. However, the introduction of gas-market hub pricing in the Netherlands has not consistently brought more affordable prices, as gas market fundamentals (that is, lack of energy alternatives) have driven gas prices higher in times of scarcity, such as during extended periods of cold weather. Since the liberalisation of gas pricing, Dutch revenues have decreased as a consequence of earthquake-related cuts in production from the Groningen gas field.

By contrast, during the same 1990s period Australia relied on (and still relies on) low cost, coal-fired power stations as its major energy source. This is backed by a strong industry lobby and political support.[125] Gas is a major energy source for heating,[126] but since the 2000s competing demands from domestic and export

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121 Paul Kay, Parliamentary Research Service, 'Natural Gas: An Australian Growth Industry?' (Research Paper No 2, Department of the Parliamentary Libary, 1994).

122 Ross Garnaut and Anthony Clunies Ross, *Taxation of Mineral Rents* (Clarendon Press, 1983).

123 See Diane Kraal, 'Australia's Petroleum Resource Rent Tax: Paul Keating, Peter Walsh and Other Game Changers' (2016) 25(4) *Griffith Law Review* 492, 499.

124 Australia signed the *Kyoto Protocol to the United Nations Framework Convention on Climate Change*, opened for signature 11 December 1997, 2303 UNTS 162 (entered into force 16 February 2005) in 1998 and ratified it in 2007.

125 See, eg, Commonwealth, *Parliamentary Debates*, Senate, 14 February 2017, 781–2 (Matt Canavan, Minister for Resources and Northern Australia).

126 Australia has proved natural gas reserves of 2.4 Tcm at the end of 2018, *BP Statistical Review of World Energy* (Report, 68th ed, 2019) 30.

customers have placed strains on gas availability and affordability. These strains have become divisive political issues in Australia.[127] Reasonable levels of PRRT revenues from gas would be invaluable as tax redistribution could be applied to the alleviation of energy poverty and widen energy affordability and sustainability in the community. We contend that the current *PRRTA Regulation* RPM method for gas transfer pricing is a clear factor in low tax revenues. The vastness and cheapness of coal reserves in Australia has made it complacent, with little motivation for change while government is seen to have mismanaged gas resources.

Since the 2000s, the Netherlands' concerns about the environmental sustainability of gas supply have intensified, as a result of gas extraction-related earthquakes and with recognition of the need to reduce CO_2 emissions. These were contributory factors to the government passing the abandonment of the 'access to grid' legislation in 2017, followed by legislation to lower gas production levels to zero by 2030.[128] Both changes were necessary intra and intergenerational issues and seen as necessary to the nation's transition from fossil fuels to renewable energy.

By contrast, from the early 2000s, Australia has seen a rise in LNG gas projects.[129] In 2017 Chevron's large Wheatstone LNG project commenced production for export. The environmental damage from this gas field's CO_2 emissions has been foreshadowed for review.[130] Australia's repeal of the carbon-tax legislation, *Clean Energy Legislation (Carbon Tax Repeal) Act 2014* (Cth) has resulted in the failure to deliver any meaningful impact on reducing CO_2 emissions. In fact, increased emissions for the past year are linked to LNG production for export.[131] To address the GTP on the basis of distributional justice, PRRT revenues from gas extraction could be applied towards better environmental outcomes.

A key lesson from the Dutch is their *political decisiveness* in policy changes for better environmental outcomes, however Australia's lack of political decisiveness whether it is to address problems of low gas revenues or control carbon emissions. Compared to the Netherlands, in Australia, energy policy is low on the political agenda of the current Morrison government. This is illustrated by the Australian government's revised energy policy that preferences

127 See Australian Competition and Consumer Commission, *Gas Inquiry 2017–2020: Interim Report* (September 2017); Australian Industry Group, *Energy Shock: No Gas, No Power, No Future?* (Report, February 2017); Tony Wood and David Blowers, Grattan Institute, *Price Shock: Is the Retail Electricity Market Failing Consumers?* (Report No 2017-04, March 2017).

128 Mulder and Perey, 'Role of the Groningen Gas Field' (n 59) 14, 16.

129 Department of Industry and Science (Cth), 'Resources and Energy Major Projects', (Presentation, April 2015), 10, archived at <https://webarchive.nla.gov.au/awa/20190422091236/https://archive.industry.gov.au/Office-of-the-Chief-Economist/Publications/Documents/remp/REMP-April-2015.pdf>.

130 Brad Thompson, 'Chevron's Wheatstone LNG Project Caught in Greenhouse Gas Emissions Row', *Australian Financial Review* (online, 23 January 2018) <http://www.afr.com/business/chevrons-wheatstone-lng-project-caught-in-greenhouse-gas-emissions-row-20180123-h0n0cs#ixzz5CuDEZWpS>.

131 Annual GHG emissions increased by 0.9% to September 2018. Department of Environment and Energy (Cth), 'Quarterly Update of Australia's National Greenhouse Gas Inventory' (Quarterly Update, September 2018) 3, 6–7.

coal-fired power stations for primary energy.[132] Moreover, to sell energy resources that are under-taxed and sold for export to the extent that there are national shortages is an intra- and intergenerational issue.[133] To address gas shortages there are plans to import LNG into Australia by late 2022.[134]

Table 1 below summarises the energy justice issues from the preceding discussion. It shows economics and politics have always dominated the discourse on petroleum resources in Australia, while for the Netherlands, the economic benefits of gas production have been disrupted by environmental impacts of extraction along with more progressive attitudes to carbon emissions reduction. Using this qualitative data, if we were to roughly plot the position of both countries into the energy justice triangle (per Figure 10) then Australia might be more to the top, and right, of the three vertices; while the Netherlands might be at the foot of the triangle at the mid-point. The ideal position is to be in balance, in the middle of the triangle.

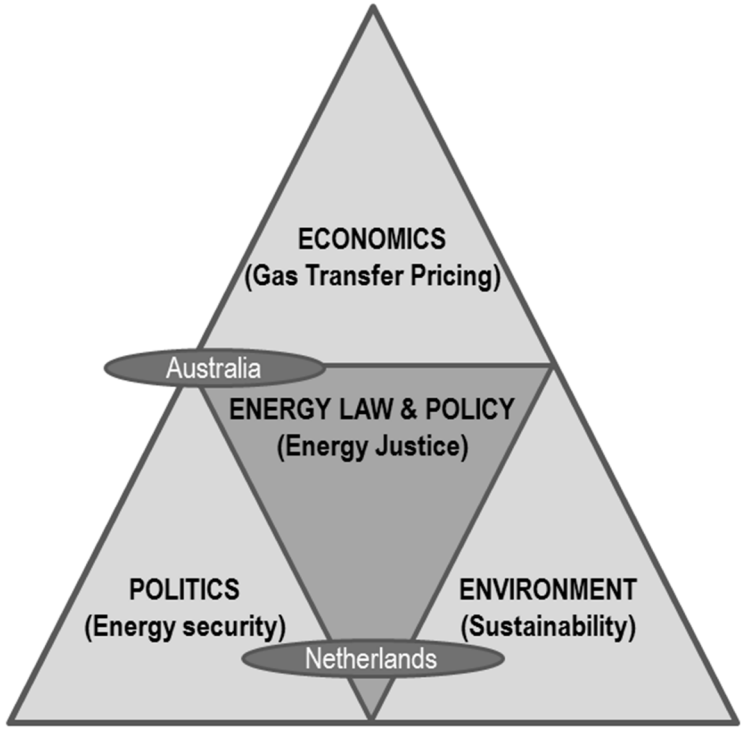

Figure 10: The Triangle of Energy Law and Policy

132 'Our Plan' (n 119).
133 Marsden argues for a more comprehensive energy law and policy: Marsden (n 54).
134 AGL, 'Update on Crib Point Gas Import Project' (Media Release, 28 June 2019).

Table 1: Summary of Energy Justice Issues

		Economic	Political	Environmental
Australia	1960s	Availability of gas; low cost.		
	1970s		OPEC oil crisis. Policy of energy security an issue.	
	1980s		PRRT introduced in response to policy of energy security.	
	1990s	Reliance on low-cost coal for primary energy. Gas is a secondary energy source.	Strong coal lobby drives energy policy.	
	2000s	Affordability and availability of gas becomes an issue.	PRRT regulations affect gas pricing. Three PRRT reviews, 2017 and 2018. Industry lobby against legislative change. Intergenerational equity is a low policy priority.	Environmental concerns are low priority.
The Netherlands	1960s	Availability of gas, low cost		
	1970s		OPEC oil crisis. Policy of energy security an issue. Government directs gas production cut; addresses intergenerational equity.	
	1980s	Good availability and affordability of gas.		
	1990s	Affordability of gas becomes an issue due to regulated gas pricing.		
	2000s	State budget affected by drop in gas production	Government legislates to cut gas production. Gas extraction will cease by 2030.	Environmental sustainability of gas becomes issue due to earthquakes and the need for lower carbon emissions.

VII RECOMMENDATION AND CONCLUSIONS

Changing regulation 20(5) of the *PRRTA Regulation* and associated provisions that prescribe the use of the RPM and replacing it with the netback method is recommended. The RPM is the current method that taxpayers must use to determine the price of sales gas (also known as feedstock gas) in cases where there is no advance pricing arrangement with the Australian Taxation Office or arms-length price. The recommended change should take effect immediately for all current integrated LNG projects. This recommendation requires the replacement of one outdated principle that underpins the formation of the GTP: assessment against economic efficiency criteria. The 21st century expectation is that economic imperatives must be in balance with principles from the politics of energy security and the environment.

Reform of gas regulations is supported by the Australian Senate inquiry report recommendations in regard to corporate tax avoidance in the offshore oil and gas industry. The Senate noted that the gas transfer pricing method for the PRRT should be simpler and more transparent so as to ensure that it delivers a fair return to the community.

Reform is supported by our research modelling findings and the PRRT objective of taxing economic rent. The netback method alone is argued as more appropriate, providing a fairer price between owners and industry as well as higher tax revenue. The current RPM advantages industry to the detriment of the community, the owners of the nation's gas resources.

A change to the proposed netback method for the PRRT GTP would also harmonise all resource calculation methods around Australia. Sovereign risk concerns about reform are overstated. Sovereign risk is characterised by overt changes, such as nationalisation of resources, certainly not tax regulatory changes.

In terms of energy justice, reform is likely to enable higher PRRT revenues from gas. Tax redistribution is a means to alleviate energy poverty and widen affordability in the community. Further, as a matter of distributional justice, higher revenues from gas extraction could be applied towards better environmental outcomes. To sell energy resources that are undertaxed and sold for export to the extent that there are national shortages transgresses the energy justice principle of intra- and intergenerational equity.

In the Netherlands, gas has been extracted from its extensive Groningen gas fields since the 1960s. The fields supply consumers and businesses in the Netherlands as well as the EU export market. Since the 1960s the government has received around EUR288 billion in gas revenues; while Shell and ExxonMobil have received EUR29 billion from Dutch gas revenues. The opposite distribution of gas revenues appears to be the situation for Australia's gas resources.

The 2018 final government response to the *Callaghan Report* has called for a review of the GTP regulations during 2019 to early 2020. This article contributes to the debate for regulation reform.

APPENDIX

A Technical Explanation of the RPM (to Calculate GTP) in the FARI Model

The main design features in the RPM, which allocates value to the upstream or downstream parts of an integrated gas project, include:[135]

1. Upstream capital cost allocation. This process determines the minimum return required to reward capital invested in either upstream, eg, subsea pipelines.
    a. Upstream capital costs (cost-plus method). Development and replacement capital costs are allocated in proportion to export gas volumes (tbtu/d) from the 'final investment decision' date ('FID') to end of the project life.[136]
    b. Augmented upstream capital costs (cost-plus method). For N years before production starts, annual upstream capital costs are increased by the long term bond rate ('LTBR') and 7% capital uplift factor:

    $$[1 + (\mathrm{LTBR} + 0.07)]^{\mathrm{N}}$$

    c. Then augmented capital costs, and annual capital costs from production date, are added together and allocated across production years in proportion to export gas volumes for each year of the project life.
2. Downstream capital cost allocation. This process determines the maximum return required to reward capital invested in downstream, eg, liquefaction plant.
    a. Downstream capital costs (netback method). Development and replacement capital costs are allocated in proportion to export gas volumes (tbtu/d) from the FID to end of the project life.
    b. Augmented upstream capital costs (netback method). For N years before production starts, annual downstream capital costs are increased by:

    $$[1 + (\mathrm{LTBR} + 0.07)]^{\mathrm{N}}$$

    c. Then augmented capital costs, and annual capital costs from production date, are added together and allocated across

135 See *PRRTA Regulation* ss 30–42.
136 Definition of 'tbtu/d': trillion British thermal units per day.

production years in proportion to export gas volumes for each year of the project life.

3. Capital allowance rate. This rate represents the rate of reward for capital invested. The regulated rate is 7% plus the Long Term Bond Rate, for both upstream and downstream.
4. Division of the residual profit element ('residual profit split'). The 'residual profit' or economic rent is the difference between the cost-plus price and the netback price. The regulations require the prices to be added together, then a 50:50 split to derive the GTP.
5. Asymmetric treatment in loss situations. Most times the netback price will be higher than the cost-plus price. However, if the cost-plus price is higher (a loss situation) the regulations require the use of the lower netback price (an asymmetric treatment).
6. The *cost-plus price* formula is:

$$\frac{\text{(Upstream capital costs x Quantity coefficient) + Upstream operating costs}}{\text{Quantity of assessable gas}}$$[137]

7. The *netback* formula is:

$$\text{Export value} - \text{(Downstream capital costs x Quantity coefficient)} + \text{Downstream operating costs} / \text{Quantity of assessable gas, minus, Downstream personnel costs} / \text{quantity of taxpayer's downstream}$$[138]

B Application of RPM regulations

Commodity production volumes were converted to a common base of tbtu/per day. A pro rata factor based on export gas volumes was used for operating costs.

For the netback calculation, data inputs included export LNG revenue and downstream cash costs, both capital and operating (but exclude debt interest). A capital uplift of 7% plus the Australian LTBR of 1.9% was applied to 'downstream pre-production capital costs' that were also discounted by the number of years to the start of production. Then the pre-production capital costs were allocated annually from the start of production, on the basis of export volumes. Operating costs ('opex') were allocated on a pro rata basis. An inflation factor of 2% was added to forecast figures from 2018, and then compounded. Then from the first year of production, capex and opex costs were added up and deducted from LNG revenue to derive net revenue. Net revenue was divided by export gas volumes to derive the netback price/mcf. The netback price represents the highest notional price the 'downstream' operation (which includes the liquefaction, sales and marketing costs) would pay for the gas. In cases where the

137 See above n 46 for cost-plus formula.
138 See above n 47 for netback formula.

netback price was lower than the cost-plus price, the netback price was used. There is no carry forward of costs in a loss situation.

For the cost-plus calculation, data inputs are capital and operating cash costs (but exclude debt interest). A capital uplift of 7% plus the LTBR of 1.9% was applied to upstream pre-production capital costs, which were also discounted by the number of years to the start of production. Then the pre-production capital costs were allocated annually from the start of production, on the basis of export volumes. Opex were allocated on a pro rata basis. An inflation factor of 2% was added to forecast figures from 2018. Then from the first year of production, capex and opex costs were added up and divided by export gas volumes to derive the cost-plus price/mcf. The cost-plus price represents the lowest notional price the 'upstream' operation would sell the sales gas/feedstock gas to the 'downstream' operation. The regulations require that the cost-plus method excludes the value of the gas reserves and exploration costs.

Table 2: Snapshot of Modelling for RPM (for GTP Calculation), Woodside Petroleum's 'Pluto LNG' Project

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Inflation					1	1	1	1	1	1
Capital uplift	7%									
Long Term Bond Rate (LTBR)	1.9%									
Years to production (N)	5	3	2	1						
Condensate production	Mbpd	0	0	0	6	8	9	8	11	10
Export gas production	mmcfd	0	0	0	393	574	665	621	717	701
Domestic gas production	mmcfd	0	0	0	0.1	0.1	0.1	0.1	0.1	0.1
Conversion: MMBtu/bbl		6	6	6	6	6	6	6	6	6
Conversion: Btu/Cf		1050	1050	1050	1050	1050	1050	1050	1050	1050
Condensate production	tbtu/d	0	0	0	35	47	53	50	65	62
Export gas production	tbtu/d	0	0	0	413	603	698	652	752	736
Domestic gas production	tbtu/d	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	448	650	751	702	817	798
Pro rata factor for opex based on export gas production	0.92	0.92	0.92	0.92	0.92	0.93	0.93	0.93	0.92	0.92
Netback, calculation (real)										
Export LNG, revenue (USD million)					1210	1851	3016	1508	1363	1858
Less downstream costs										
– Capital costs (USD million)	2163	2013	1941	1850	600	60	0	45	0	45
Augmented: Cap cost x (1+ at LTBR +7%)^{N} (USD million)	3313	2600	2302	2015						

Pre-production. Capital costs allocation (based on Bcf export gas volumes) (USD million)					336	491	569	530	612	599
– Opex, pro rata (USD million)					70	81	81	64	58	63
Netback, calculation (nominal)										
Net revenue (USD million)					204	1219	2366	869	692	1152
Export gas volumes (Bcf)					144	210	243	226	262	256
Netback price (net rev/export gas volume) (USD/mcf)					1.42	5.82	9.74	3.83	2.65	4.50
Cost-plus, calculation (real)										
Add GTL upstream costs										
– Capital costs, pro rata for export gas (USD million)	1875	1593	668	377	378	135	262	183	208	62
Augmented: Cap cost x (1+ at LTBR +7%)^{N}	2872	2057	793	410						
Pre-production capital costs allocation (based on Bcf export gas volumes) (USD million)					202	294	341	318	367	359
– Opex, pro rata (USD million)					114	131	131	105	94	61
Cost-plus, calculation (nominal)										
Costs (USD million)					693	560	734	606	669	482
Cost-plus price (costs/export gas volume) (USD/mcf)					4.83	2.67	3.02	2.67	2.56	1.88
Gas Transfer Price = netback + cost plus/2 (USD/mcf)					$ 1.42	$ 4.24	$6.38	$3.25	$ 2.60	$3.19

Source: Authors, from FARI model and Wood Mackenzie data.

Table 3: Key Sources and Assumptions for GTP Modelling

Item	Source	Assumption
Inflation factor		Yes
Capital uplift	*PRRTA Regulation*	No
Long Term Bond Rate		Yes
LNG export revenue (Price x volume)	Wood Mackenzie	No
Production volumes	Wood Mackenzie	No
Operating costs	Wood Mackenzie	No
Capital costs	Wood Mackenzie	No
Augmented capital cost factor	*PRRTA Regulation*	No
Pre-production capital costs allocation	*PRRTA Regulation*	No