



Australian Government
**Department of Industry,
Innovation and Science**

Submission to the Senate Economics References Committee

Inquiry into Australia's oil and gas reserves

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Introduction

Australia's prosperity and status as a leading energy supplier to the world depends on retaining and attracting investment in our resources sector.

Australia's oil and gas development have been supported by a stable regulatory framework that supports Australia's world leading oil and gas industry to deliver mutually beneficial outcomes.

Australia's giant gas field discoveries have led to world-leading projects and first-class infrastructure. These include the Pluto, Wheatstone, Gorgon, Ichthys, Prelude, Curtis, Gladstone and Australia-Pacific liquefied natural gas (LNG) projects. The decisions to invest by these projects' joint venture partners are backed by the high-grade reserves in their foundation petroleum production licences and the expectation of additional resources that can be developed over the very long lives of these projects.

Benefits to the Australian community from these projects are diffuse. They include the provision of high-quality jobs, business opportunities and infrastructure in regional areas, creation of a reliable and stable source of energy both domestically and for our trading partners, and the generation of significant tax and royalty revenue streams over the lives of these projects.

Australia's oil and gas industry

Australia's oil and gas industry is underpinned by substantial reserves and resources, the development of which strengthens Australia's position as a leading global market participant. Over time, the focus of Australia's upstream petroleum industry has shifted from oil towards gas development. This has been a consequence of limited new oil discoveries to replace depleting reserves in existing fields, and the discovery of major new gas resources underpinning substantial investment to meet growing gas demand.

Australia's oil and gas industry is a major multi-billion dollar contributor to Australia's prosperity, energy security, employment and terms of trade. Investment exceeding AU\$340 billion in Australia's oil and gas sector since 2009 has fuelled opportunity and growth.¹

The industry has adapted to global demand patterns, and developed and adopted innovative technologies.

¹ Resources and Energy Quarterly September 2019, Historical Data,
<https://publications.industry.gov.au/publications/resourcesandenergyquarterlyseptember2019/documents/REQ-September-2019-Historical-Data.xlsx>

Energy and investment

Australian oil and gas products play an important role in meeting the energy needs of the domestic market, as well as those of countries in our region. The exports created by the LNG industry has driven significant investment in Australia and diversification in our petroleum export products.

Australia is a significant net importer of oil and net exporter of gas. Australia produced 646 petajoules (PJ) of oil, equivalent to 106 million barrels of oil equivalent (mmboe), and 4731 PJ of gas in the 2017-18 financial year.² In comparison, over the same period Australia consumed 2,387 PJ (390 mmboe) of oil and 1555 PJ of gas.³ Australia produced 572 PJ (93 mmboe) of crude oil and 1,103 PJ (180 mmboe) of petroleum products in 2017-18, equivalent to approximately 50 per cent and 48 per cent of Australian consumption of these products, respectively.⁴

As one of the world's two largest exporters of LNG (along with Qatar), Australia has a solid reputation as a reliable long-term energy supplier to growing Asian energy markets. This supply is generated by the ten operating LNG projects in Australia – seven supplied by gas from Australia's offshore waters and three supplied by east coast onshore gas. Attachment A provides a summary of Australia's LNG facilities, their ownership, development milestones, production capacity and capital investment.

Offshore, the foundation North-West Shelf project has exported LNG for 30 years and provided gas to the domestic Western Australia market for 35 years. It has been followed by six other LNG developments in Western Australia and the Northern Territory. The scale of capital investment required for an LNG plant to be commercial has dictated that these projects take joint venture partnership approaches to support development.

Advances in technology associated with developing coal seam gas (CSG) and high growth in gas demand in Asia has led to substantial investment in Queensland's CSG industry, primarily for the purpose of LNG exports. The three east coast LNG facilities are all now fully operational. These facilities represent a total investment of over \$70 billion.⁵ Concurrently, there has been substantial investment in CSG fields in Queensland, primarily in the Surat and Bowen Basins in Queensland. In the last ten years, over 7000 gas production wells were drilled in Queensland.⁶

LNG projects in Western Australia and the Northern Territory represent 71 per cent of Australia's installed LNG production capacity of 88 million tonnes per year. The three LNG

² Australian Energy Statistics 2019, Table A

³ *ibid*

⁴ *ibid*

⁵ <https://www.business.qld.gov.au/industries/invest/mining/resources-potential/petroleum-gas>

⁶ www.energyedge.com.au/Products/GasMarketAnalysisTool.aspx.

projects in Queensland represent 29 per cent of capacity and are supplied primarily by onshore CSG fields in Queensland.

About 70 per cent of Australia's crude oil and condensate is from Western Australia.⁷ Most of the State's production is in the Browse, Carnarvon and Perth Basins.

The Gippsland Basin is the dominant source of offshore gas supply to south east Australia, with about half of total demand for domestic gas supplied through the Longford Gas Plant on the coast of south east Victoria. The second major source of gas supply to south east Australia is the Cooper/Eromanga Basin, which extends across north east South Australia and south west Queensland. Gas from this basin is processed at the Moomba Gas Plant located in north east South Australia, which also supplies gas to the Queensland domestic market and the east coast LNG facilities.

Petroleum exploration expenditure (both onshore and offshore) was \$1260 million in the 2018-19 financial year, up 23 per cent year-on-year.⁸ Prior to this year, exploration expenditure fell for four years, and the 2018-19 result indicates that 2017-18 may have been a cyclical low point for exploration expenditure. Higher oil prices in Australian dollar terms and domestic gas prices on the east coast may have motivated a modest return of confidence in the oil and gas industry.⁹

Economy and export value

The large LNG investments over the past decade continue to contribute significantly to Australia's economy – in February 2018, the Reserve Bank of Australia forecast that LNG exports would contribute around a quarter percentage point in GDP growth per year over 2018 and 2019.¹⁰ The May 2019 Statement on Monetary Policy by the Reserve Bank of Australia¹¹ confirmed that LNG exports continued to grow strongly and are expected to increase slightly more over the next year or so, as production from the final LNG projects in Western Australia continue ramping up.

In 2018-19 the value of Australian oil and gas exports was just over AU\$62 billion.¹² The vast majority of this - \$50 billion – was LNG. Figure 1 shows the growth in Australian LNG exports over the last decade. Export earnings from LNG are forecast to lift to \$52 billion in 2019–20, driven by growing export volumes, before falling back to \$49 billion in 2020-21, as prices ease.¹³ Australian LNG export prices are forecast to decline slightly in 2019–20 and 2020–21, due to an appreciating exchange rate and lower oil-linked contract prices (at which most

⁷ Department of the Environment and Energy, Australian Petroleum Statistics August 2019, <https://www.energy.gov.au/publications/australian-petroleum-statistics-2019>

⁸ ABS 8412.0 Mineral and Petroleum Expenditure Australia, Sep 2019 – Table 1

⁹ Resources and Energy Quarterly June 2019, p. 68 ,

¹⁰ <https://www.rba.gov.au/publications/smp/2018/feb/pdf/statement-on-monetary-policy-2018-02.pdf>

¹¹ <https://www.rba.gov.au/publications/smp/2019/may/pdf/statement-on-monetary-policy-2019-05.pdf>

¹² Department of Industry, Innovation and Science, Resources and Energy Quarterly September 2019

¹³ Department of Industry, Innovation and Science, Resources and Energy Quarterly September 2019

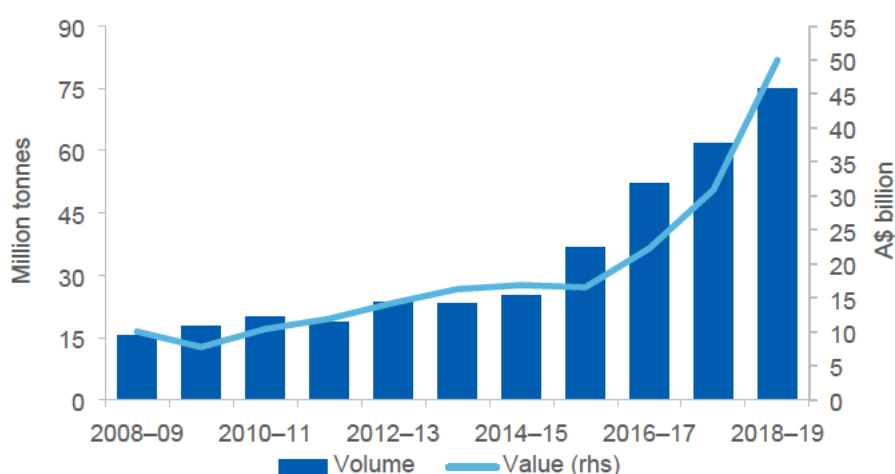
Australian LNG is sold). There is also downward pressure on Asian LNG spot prices as new supply capacity in the US and Russia ramps up.

In August 2019, the Oil and Gas Extraction sector directly employed 26,100 people.¹⁴ In 2017-18, the industry paid \$3.7 billion to employees of the sector.¹⁵ The oil and gas industry also paid over AU\$1 billion in Petroleum Resource Rent Tax in 2017-18.¹⁶

The composition of Australia's oil exports is changing, with condensate exports growing strongly since 2015 while crude oil exports have declined. Condensate output is forecast to grow 10 per cent a year. The start-up of INPEX's Ichthys facility in late 2018 has resulted in new condensate production.

The presence of condensate in new gas field developments can be an important factor in determining project commerciality as it adds an additional income stream for the project.

Figure 1: Australian LNG export volumes and values



Source: Resources and Energy Quarterly September 2019, Historical Data, <https://publications.industry.gov.au/publications/resourcesandenergyquarterlyseptember2019/documents/REQ-September-2019-Historical-Data.xlsx>

The future of Australia's oil and gas industry

Table 1 shows Australia's oil and gas resources as assessed in 2015. Australia's economic demonstrated reserves included 123,187 PJ of gas and 13,340 PJ of oil. Total demonstrated resources included 279,685 PJ of gas and 29,486 PJ of oil.

Table 1 Australian oil and gas resources in 2015

¹⁴ ABS 6291.0.55.003 Labour Force, Australia, Detailed, Quarterly, Aug 2019 – Table 6

¹⁵ ABS 8155.0 Australian Industry, 2017-18 - Table 1

¹⁶ Australian Government, Final Budget Outcome 2018-19

Resource	Unit	Economic Demonstrated Resources	Total Demonstrated Resources ^a
Crude oil	PJ	3286 ^b	7066 ^c
Condensate	PJ	7421 ^b	16 463 ^c
LPG	PJ	2633 ^b	5957 ^c
Shale oil	PJ	0 ^b	0 ^c
Oil shale	PJ	0 ^b	0 ^c
Conventional gas	PJ	77 253 ^b	186 235 ^c
Coal seam gas	PJ	45 895 ^b	79 450 ^c
Tight gas	PJ	39 ^b	1748 ^c
Shale gas	PJ	0 ^b	12 252 ^c
Total Oil	PJ	13 340	29 486
Total Gas	PJ	123 187	279 685

Notes: a. Includes Economic Demonstrated Resources and Subeconomic Demonstrated Resources; b. Includes reserves; c. Includes reserves and contingent resources.

Source: Geoscience Australia, Australian Energy Resource Assessment, <https://aera.ga.gov.au/>

Offshore

Future gas demand is expected to encourage ongoing development of existing offshore gas fields and stimulate new offshore gas projects. These developments will be assisted by continuing industry activity as projects come on-line, field sequencing for major projects is determined, wells are drilled to reduce uncertainty and collaborative commercial developments are progressed.

Future development of Australia's offshore gas resources is less likely to involve the integrated development of new upstream and downstream infrastructure. Instead, it is more likely to involve the development of new fields as backfill or the incremental expansion of existing infrastructure. This is a consequence of declining production from foundation projects and the economics of developing greenfield facilities in a country that already has ten operational LNG projects, some of which have space for future expansion. While some of these will be large fields, many of these will be smaller as industry needs to utilise smaller, more distant, or more technically complex fields for infill.

To realise the development of these smaller and often more isolated fields, industry collaboration is likely to be critical. Collaboration can spread the risk on project investments, encourage third-party participants, enable third-party infrastructure access (and development) and foster equitable tolling arrangements. Collaboration will underpin the next wave of development of Australia's offshore resources.

Tightness in domestic gas markets is providing incentives to explore and develop offshore fields that have traditionally been considered sub-economic. These fields are directly linked

to existing domestic gas supply infrastructure rather than export focused LNG plants. This renewed interest is particularly evident in the offshore Gippsland and Otway Basins.

Failure to realise Australia's offshore resources potential could result in inefficient infrastructure use, sub-optimal and delayed development outcomes and stranded fields. This has flow-on effects to the broader economy, the sustainability of regional areas, small and medium businesses and employment.

Onshore

While Australia has substantial onshore gas resources, much of this has traditionally been an uneconomic alternative to conventional offshore gas. However, advances in technology associated with developing coal seam gas (CSG), supportive government policies, particularly in Queensland, and gas demand in Asia has led to substantial investment in Queensland's CSG industry, primarily for the purpose of LNG exports.

State moratoria and regulations of onshore gas in southern markets have limited new gas resource developments. Victoria and Tasmania have state-wide moratoria, South Australia has a moratorium in the south-east of the state. New South Wales has established a number of restrictions on unconventional gas development, including exclusion zones near residential areas and some primary industries. The Narrabri Gas Project, which could supply up to 50 per cent of NSW natural gas needs, is waiting on NSW regulatory approvals.¹⁷ The potential for developments in jurisdictions and regions that have moratoria in place will be heavily contingent on policy decisions of the relevant jurisdictional government.

Where policy conditions are conducive to development of onshore oil and gas projects, market conditions are likely to drive investment outcomes. In Eastern Australia, lower-cost, primarily offshore, conventional gas reserves are in decline. If additional gas resources are not developed close to major markets, some regions of Australia will increasingly need to source gas from interstate. This increases the cost of supply due to transportation costs and introduces additional risk to supply reliability if there is insufficient pipeline capacity available during peak demand periods.

The Northern Territory Government's recent removal of a moratorium on exploration and hydraulic fracturing for onshore gas in the Beetaloo Basin and the potential successful development of the basin's shale gas resources could lead to additional gas supply and an expanded Northern Gas Pipeline (NGP), which has connected the Northern Territory to the eastern gas market since January 2019. In anticipation of more supply, the NGP operator,

¹⁷ Santos, Narrabri Gas Project, <https://www.santos.com/what-we-do/activities/new-south-wales/gunnedah-basin/narrabri-gas-project>

Jemena, is considering a potential \$3 billion to \$4 billion expansion of capacity from 35 PJ per year to 255 PJ per year.¹⁸

A number of other new pipelines are under development, including the Reedy Creek to Wallumbilla Pipeline, which was commissioned in June 2018, the Atlas Gas Pipeline, which is expected to open at the end of 2019 and the Galilee Gas Pipeline, which is expected to open in 2022.

Over the past two years, the Queensland Government has issued tenements with domestic supply conditions to six different gas producers.¹⁹ Gas produced from each of these tenements must be sold domestically. The first gas from these tenements is expected from 'Project Atlas' in 2019. Senex estimates that the project has 144 PJ of commercially recoverable reserves.²⁰

Australia's framework for development of oil and gas reserves

Governments around the world take a variety of approaches to development of their natural resource endowments that take account of the particular circumstances in those countries. Australian governments take a unique approach to development of our oil and gas resources that reflects our federated system, historical developments in the sector and the nature of the resources themselves.

Offshore projects

Primary responsibility for Australia's offshore areas beyond three nautical miles from the territorial sea baseline is vested in the Commonwealth Government. In practice, the Commonwealth jointly administers each offshore area with the affected state or Northern Territory government.

In these areas, the Commonwealth provides a petroleum resource management framework to support development of Australia's offshore oil and gas resources. This framework promotes the timely discovery and development of petroleum resources for the economic benefit of the Australian community, while also ensuring that activities are undertaken safely and in an environmentally responsible way and in accordance with good oil field practice

¹⁸ Jemena, Missing Gas Pipeline Link Complete [<http://jemena.com.au/about/newsroom/media-release/2018/missing-gas-pipeline-link-complete>]

¹⁹ ACCC, *Gas Inquiry 2017–2020 Interim Report*, July 2019, p. 37.

²⁰ Senex, 2018 Annual Reserves Statement, 31 July 2018, [<https://www.senexenergy.com.au/wp-content/uploads/2018/07/2018.07.31-2018-Annual-Reserves-Statement.pdf>]

principles. It includes a range of policy and regulatory measures across the exploration-discovery-development-decommissioning lifecycle.

This framework is principally defined through the *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (the OPGGS Act). The OPGGS Act articulates a series of basic rights, entitlements and responsibilities of governments and industry for the exploration and recovery of petroleum and for injection and storage of the greenhouse gas substances in offshore areas. This provides investors with predictability and clarity on their rights, returns and obligations while ensuring a return on development to the owners of the resources, the Australian people.

To give effect to the framework, the OPGGS Act establishes: the Offshore Petroleum Joint Authorities (the Joint Authorities) for each offshore area; the National Offshore Petroleum Titles Administrator (NOPTA); and the National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA).

The Joint Authorities - The Commonwealth jointly administers the regime with affected State and Northern Territory Governments through a Joint Authority (consisting of relevant responsible Ministers) for the offshore area of each State and the Northern Territory. This authority is responsible for the majority of decision making under the OPGGS Act including the granting of petroleum titles, the imposition of title conditions and the cancellation of titles, as well as core decisions about resource management.

NOPTA – the Joint Authorities receive advice in relation to exercising their titles decision-making powers from NOPTA, which is responsible for assessing applications in relation to offshore petroleum titles and providing related reports and recommendations.

NOPTA's key functions are to:

- provide information, assessments, analysis, reports, advice and recommendations to members of the Joint Authorities and the responsible Commonwealth Minister in relation to the performance of those ministers' functions and the exercise of their powers;
- facilitate life of title administration, including but not limited to Joint Authority consideration of changes to permit conditions associated with offshore petroleum titles;
- manage the collection, management and release of title data; and
- keep the registers of petroleum and greenhouse gas storage titles.

In addition to its advisory activities, NOPTA has the authority to grant short term titles (petroleum access authority and petroleum special prospecting authority) and approves certain commercial arrangements known as transfers and dealings.

NOPSEMA - NOPSEMA is Australia's independent expert regulator for health and safety, environmental management, structural and well integrity for offshore petroleum facilities and activities in Commonwealth waters.

NOPSEMA's principal functions are to:

- promote the occupational health and safety (OHS) of persons engaged in offshore petroleum operations or offshore greenhouse gas storage operations;
- develop and implement effective monitoring and enforcement strategies to ensure compliance under the OPGGS Act and regulations;
- investigate accidents, occurrences and circumstances relating to OHS, well integrity and environmental management;
- advise on matters relating to OHS, well integrity and environmental management;
- make reports, including recommendations, to the responsible Commonwealth minister and each responsible state and Northern Territory minister; and
- cooperate with other Commonwealth and state or Northern Territory agencies or authorities having functions relating to regulated operations.

Onshore petroleum activities

Regulation of onshore petroleum activities, including state waters out to the three nautical mile limit, is primarily the responsibility of each state and territory government. This includes environmental, planning and safety regulation. While their approaches vary, regulatory regimes in each state are evolving to respond to the complex issues and community expectations surrounding oil and gas development.

The Australian Government has a regulatory role where an activity is likely to have a significant impact on a matter of national environmental significance under the *Environment Protection and Biodiversity Conservation Act 1999* (the EPBC Act). Issues defined under the EPBC Act as matters of national environmental significance, include:

- world heritage properties,
- national heritage places,
- wetlands of international importance (listed under the Ramsar Convention),
- listed threatened species and ecological communities,
- migratory species protected under international agreements,
- Commonwealth marine areas,
- the Great Barrier Reef Marine Park,
- nuclear actions (including uranium mines), and
- a water resource, in relation to CSG development and large coal mining development.

Resource charging arrangements for oil and gas projects

Australian oil and gas projects are subject to a range of industry specific tax regimes in addition to corporate tax regimes applicable to firms in other industries. Australian governments at Commonwealth, State and Territory level apply a variety of resource charging arrangements and the specific tax regime that applies to a project will typically vary based on where the project is located, in particular offshore or onshore locality, and when an investment decision was made.

The main resource charging arrangements generally consist of the Petroleum Resource Rent Tax (PRRT), crude oil and condensate excises, Commonwealth petroleum royalties and state petroleum royalties. Table 1 outlines where the different types of resource charging arrangements apply in Australia.

Table 1 — Summary of resource charging arrangements in Australia

	Petroleum Resource Rent Tax (PRRT)	Excise	State Royalties	Commonwealth Royalties	Resource Rent Royalty (RRR)
Commodities	Any naturally occurring hydrocarbon (or naturally occurring mixture of hydrocarbons) whether in gaseous, liquid or solid state. Includes oil shale.	Crude oil and condensate	Any naturally occurring hydrocarbon (or naturally occurring mixture of hydrocarbons) whether in gaseous, liquid or solid state. ^(a)	Any naturally occurring hydrocarbon (or naturally occurring mixture of hydrocarbons) whether in gaseous, liquid or solid state.	Any naturally occurring hydrocarbon (or naturally occurring mixture of hydrocarbons) whether in gaseous, liquid or solid state. Excludes oil shale.
Onshore ^(b)	No (from 1 July 2019)	Yes (excluding Barrow Island)	Yes	No	Barrow Island only
Offshore	Yes (since 1988)	North West Shelf project only	No	North West Shelf project only	No
North West Shelf project (special offshore area)	Yes (since 1 July 2012)	Yes	No	Yes. Shared with Western Australia ^(c)	No
Barrow Island (special onshore area)	Yes	No (replaced with RRR)	No (replaced with RRR)	No (replaced with RRR)	Yes (since 1985) ^(d)
Bass Strait (offshore)	Yes (since 1990-91) ^(e)	No	No	No	No

(a) Slight variations across states.

(b) Including within three nautical miles of the Australian coastline. The Commonwealth is also entitled to 40 per cent of royalties obtained by Western Australia from petroleum developments derived from pre-1979 leases which are located in the coastal waters region adjacent to Western Australia.

(c) These royalties are shared with Western Australia according to the formula set out in the *Offshore Petroleum and Greenhouse Gas Storage Act 2006* — *Section 75* (approximately one third to the Commonwealth, two thirds to Western Australia).

(d) Shared between the Commonwealth and Western Australia 75:25.

(e) Production in Bass Strait changed from a royalty/excise regime to PRRT in 1990-91.

The Department of the Treasury have responsibility for the PRRT and Commonwealth excise regimes. In most instances, State and Territory governments solely administer royalty regimes for projects located within their borders.

On 30 November 2016, then-Treasurer Morrison announced a Government review of the Commonwealth petroleum charging arrangements led by Mr Michael Callaghan AM PSM ('the Callaghan Review'). While primarily focused on the PRRT, the Callaghan Review also assessed whether the Commonwealth's crude oil excise and oil and gas royalty regimes were operating as intended. The final report of the Callaghan Review was released on 28

April 2017. The Government's final response to the Callaghan Review was released on 2 November 2018, with resulting changes taking effect from 1 July 2019.

While the terms of reference for the Senate Economics Committee's inquiry are significantly broader than those provided for the Callaghan Review, its final report covers a range of issues relevant to this inquiry and may prove a useful resource.

In addition to resource taxes, oil and gas companies pay company tax on income earned in Australia like any other company operating in Australia. Companies may also pay other state taxes including stamp duties and payroll tax.

Bespoke charging regimes

In some limited circumstances the Commonwealth and/or relevant state/territory government have entered into bespoke resource charging arrangements for certain oil and gas projects. Where this has occurred, it is primarily the result of the unique circumstances of the particular project, historical development of Australia's oil and gas charging arrangements and intensive negotiations between interested parties. It is unlikely that the charging arrangements established for individual projects are likely to be more widely applicable to the particular circumstances of future oil and gas developments.

North West Shelf royalty regime

Reflecting the jointly-owned nature of its resource inputs, royalties from the foundation North-West Shelf (NWS) project are split between the Commonwealth and the Western Australian government. This negotiated outcome is a key tenet of the foundational Offshore Constitutional Settlement (OCS) that provides certainty for commercial operations across many industries in offshore waters.

OCS arrangements include a 60:40 revenue sharing arrangement of the 10 per cent royalty rate of the well-head value of a petroleum project. Any royalties exceeding 10 per cent royalties go entirely to the State. This royalty sharing arrangement applies to the NWS project and offshore areas under State jurisdiction.

The substance of the OCS agreement in the NWS context is set out in implementing legislation. The OPGGSA and Royalty Act set out the basic legislative framework for the payment of NWS area royalties. This includes the royalty rate to be applied and how the royalties will be shared between the Australian Government and WA.

NWS royalty is paid on the value of petroleum at the wellhead. Conceptually, the point of valuation is the valve closest to the petroleum extraction point. However, as there is no sale at this point for each of the NWS commodities, the sale of product is deemed to be the first measure of value. Wellhead value is therefore a derived value from the sales value, less

eligible deductions for costs incurred for processing, transport and storage. Most NWS product is piped ashore, with the point of sale quite a distance from the wellhead.

Functions under the Royalty Act relating to the operation and administration of the NWS project, including royalties, are undertaken through a Joint Authority arrangement between WA and the Commonwealth. The current WA member of the Joint Authority is the WA Minister for Mines and Petroleum, with the responsible Commonwealth Minister currently the Minister for Resources and Northern Australia.

The day to day NWS royalty administrative functions are the responsibility of the WA delegate of the Joint Authority. The Department of Industry Innovation and Science acts on behalf of the Commonwealth delegate to ensure the accuracy and completeness of NWS royalty revenue received and subsequently paid to WA by the Commonwealth Treasury.

Resource Rent Royalty (Barrow Island special onshore zone)

The *Petroleum Revenue Act 1985* allows the waiver of Commonwealth crude oil excise and state royalty from onshore projects where a producer agrees to introduce a Resource Rent Royalty (RRR) and enters into a revenue sharing agreement with the Commonwealth. A Resource Rent Royalty operates in a similar fashion to a profits-based tax regime, like the Petroleum Resource Rent Tax, and is paid on a quarterly basis.

In 1985, the Commonwealth and WA Governments agreed that a RRR be applied to petroleum production from Barrow Island. The Commonwealth and WA share the Barrow Island RRR on a 75:25 ratio – the Commonwealth receives its share from WA.

Under the terms of the *Barrow Island Royalty Variation Agreement Act 1985* (the Act), the operator provides a RRR statement on petroleum production for the previous calendar year to the relevant WA Minister. The Act provides Western Australia with administrative responsibilities for the collection and assessment of royalties relating to the Barrow Island oilfield.

Management of supply for the domestic gas market

A key policy objective of the Commonwealth is to ensure that domestic gas users do not face a shortfall. The Commonwealth maintains a comprehensive suite of regulations designed to serve this purpose and maintain a well-functioning domestic gas market.

National Gas Law

The National Gas Law, a Schedule to the National Gas (South Australia) Act 2008, establishes obligations for gas pipelines, gas wholesale markets and a gas market bulletin

board. The Law is supported by the National Gas Rules and National Gas (South Australia) Regulations.

Australia Domestic Gas Security Mechanism (ADGSM)

The ADGSM provides the responsible Minister with the ability to restrict LNG exports on the basis of insufficient domestic supply based on an annual assessment of whether there is a likelihood of a gas supply shortfall in the domestic market. The Minister makes an assessment on the basis of advice from market participants, market analysts and bodies including the Australian Energy Market Operator (AEMO) and the Australian Competition and Consumer Commission.

If the Minister determines that there will be a domestic shortfall in the next calendar year, the Minister will calculate the Total Market Security Obligation. This is the volume of gas that LNG exporters (in aggregate) are drawing out of a domestic market that is in shortfall and could be subject to export restrictions. Once this total amount has been calculated, the Minister will then determine each project's contribution - the Exporter Market Security Obligation (EMSO). The Minister will then issue to each project an Export Permission, which is typically equal to an LNG project's EMSO subtracted from its proposed export quantity.

Under the existing mechanism guidelines, only those exporters drawing gas out of a market experiencing a shortfall can be subject to restrictions. It requires the responsible Minister to make decisions according to a timeframe intended to provide the LNG industry with certainty around their licensed volumes for the following year.

The ADGSM has been designed to be used as a measure of last resort in the event of a forecast domestic gas shortage.

Heads of Agreement

Sitting alongside the ADGSM, Heads of Agreements have been signed between the Australian Government and Queensland LNG exporters in October 2017 and again in September 2018. Under these agreements, LNG exporters have committed that in the event of a supply shortfall they will offer uncontracted gas to the domestic market before selling this gas internationally. The agreements represent an important market-based and industry-led solution to safeguard against any potential domestic gas supply shortages. The current Heads of Agreement, signed in September 2018, covers supply until the end of 2020.

Gas Acceleration Program

In 2017, the Government announced its \$26 million Gas Acceleration Program (GAP) which aims to accelerate the responsible development of onshore gas for domestic consumers. The program encourages direct investment in gas developments. It supports projects with

the greatest likelihood of securing new and significant volumes of gas for domestic consumers. GAP has delivered five grants to separate companies to accelerate the development of new gas supplies. GAP is expected to deliver additional gas to the eastern market once these projects are complete.

Attachment A

Australia's LNG development projects – as at 23 August 2019

Project	Investors (Operator in Bold)	Location Basin Plant	Final Investment Decision (FID) and First Gas (FG)	Size	Cost ²¹
North West Shelf	Woodside (16.67 percent) Shell (16.67 percent) BP Developments 16.67 percent) Chevron (16.67 percent) BHP Billiton (16.67 percent) MIMI (16.67 percent) CNOOC (gas and associated liquids 5.3 percent only)	WA Carnarvon Karratha	FG 1989 (pipeline gas in 1984)	16.9 Mtpa 5 trains	A\$34b
Darwin LNG	ConocoPhillips (56.94 percent) ENI Australia (10.99 percent) Santos (11.49 percent) INPEX (11.38 percent) JERA (6.13 percent) Tokyo Gas (3.07 percent)	NT JPDA Darwin	FG 2006	3.7 Mtpa 1 train	Not available
Pluto LNG	Woodside (90 percent) Tokyo Gas (5 percent) Kansai Electric (5 percent)	WA Carnarvon Karratha	FID 2007 FG 2012	4.9 Mtpa 1 train	A\$14.9b
Queensland Curtis LNG	Shell (50 percent T1, 97.5 percent T2) CNOOC (50 percent in T1) Tokyo Gas (2.5 percent in T2)	QLD Surat Gladstone	FID Oct 2010 FG Jan 2015	8.5 Mtpa 2 trains	A\$20.4b
Gladstone LNG	Santos (30 percent) Petronas (27.5 percent) Total (27.5 percent) KOGAS (15 percent)	QLD Bowen and Surat Gladstone	FID Jan 2011 FG Oct 2015	7.8 Mtpa 2 trains	A\$18.5b
Australia- Pacific LNG	Origin Energy (37.5 percent) ConocoPhillips (37.5 percent) Sinopec (25 percent)	QLD Bowen and Surat Gladstone	FID T1 Jul 2011 T2 Jul 2012 FG Jan 2016	9 Mtpa 2 trains	A\$24.7b

²¹ Estimates from company statements, public presentations and industry estimates.

Gorgon LNG	Chevron (47.333 percent) ExxonMobil (25 percent) Shell (25 percent) Osaka Gas (1.25 percent) Tokyo Gas (1 percent) JERA (0.417 percent)	WA Carnarvon Barrow Island	FID 2009 FG Mar 2016	LNG – 15.6 Mtpa 3 trains	US\$60b
Wheatstone LNG	Chevron (64.14 percent*) Woodside (13 percent) KUFPEC (13.4 percent) Kyushu Electric (1.46 percent), PE Wheatstone part owned by JERA (8 percent) *Plant. Gas field Chevron (80.17 percent and PEW 10 percent)	WA Carnarvon Onslow	FID Sept 2011 FG Oct -2017	LNG - 8.9 Mtpa 2 trains	US\$34b
Ichthys LNG	INPEX (62.245 percent) Total (30 percent) CPC Corporation Taiwan (2.625 percent) Tokyo Gas (1.575 percent) Osaka Gas (1.2 percent) Kansai Electric Power (1.2 percent) Chubu Electric (0.735 percent) Toho Gas (0.42 percent)	WA Browse Darwin	FID Jan 2012 FG Nov 2018	8.9 Mtpa 2 trains	Over US\$45b
Prelude Floating LNG	Shell (67.5 percent) INPEX (17.5 percent) KOGAS (10 percent) OPIC (CPC Taiwan) (5 percent)	WA Browse	FID May 2011 FG 18	3.6 Mtpa 1 train	US\$12.6b